Minnesota Building Decarbonization Analysis

Equitable and cost-effective pathways toward net-zero emissions for homes and businesses

Prepared for Clean Heat Minnesota

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Citizens Utility Board of Minnesota
Comunidades Organizado El Poder y La Acción Latina
Fresh Energy
Minnesota Center for Environmental Advocacy
Sierra Club

Letter from the Steering Committee:

Dear Readers:

By law, it is the goal of the State of Minnesota to reach net zero greenhouse gas emissions by 2050. The Intergovernmental Panel on Climate Change is calling for urgent action to address climate change, as are many others. Meanwhile, emissions from Minnesota buildings are on the rise. If Minnesota is to achieve its net zero goal, we must transition to carbon-free heating for our homes and businesses as soon as possible.

The Clean Heat Minnesota coalition commissioned this study to compare different pathways for decarbonizing natural gas end uses in Minnesota's residential and commercial buildings. Our goal was to gain insights into how Minnesota can decarbonize our buildings in the most cost-effective and equitable manner.

We engaged Synapse Energy Economics to analyze the costs and emissions impacts of two scenarios: one path that fully electrifies heating in Minnesota's buildings, and another that maximizes the use of renewable natural gas (RNG), a substitute for fossil gas that is derived from organic matter. Their analysis modeled energy consumption of space heating, water heating, cooking, and clothes drying in residential and commercial buildings, and the effects that changes in energy consumption will have on gas and electric utilities and their customers. The two distinct pathways analyzed provide a sense of the pros and cons with either approach. They are not intended to be precise predictions but rather bookends to illustrate key choices available to our state.

The analysis points to several clear conclusions about Minnesota's path to clean heat.

> **Both costs and emissions are likely to be lower if Minnesota fully electrifies heat.** Total costs for equipment, fuel supply, the electric sector, and the gas system are expected to be lower in the Full Electrification scenario by about 25% (approximately $13 to $15 billion)—and savings are even higher if you factor in the cost of air quality impacts and other environmental externalities. Further, relying on RNG will not, itself, eliminate greenhouse gas emissions. Reaching net zero in this scenario will require the purchase of offsets, which are not included in these cost estimates.
>
> Transitioning away from burning gas in our homes and businesses will also provide substantial health advantages by improving air quality. These advantages are particularly likely to benefit environmental justice communities, which are disproportionately impacted by air pollution.
>
> **Gas usage must decrease dramatically to reach net zero, even under the most optimistic assumptions about the availability of RNG.** To estimate the total amount of RNG that could be available to Minnesota, the study adopted projections by ICF International for the American Gas

Foundation. Even using the upper-bound projection from this assessment and assuming no RNG will be used in the transportation sector, the study found that there would only be enough RNG available to replace about 16% of the natural gas currently used by Minnesota's residential and commercial sectors. The remaining 84% of building heat must be met through electrification or other means.

Electric air-source heat pumps are a no-regrets strategy. Because the supply of alternative fuels will be limited, getting to clean heat is going to require broad deployment of electric heat pumps, whether the state eventually relies on RNG for building heating or not. To reach its greenhouse gas emission reduction goals, Minnesota must aggressively adopt electric air-source heat pumps in our homes and businesses—reaching more than 100,000 heat pumps installed annually by 2030. The majority of this adoption can be achieved by replacing gas furnaces at the end of their lives.

Electricity demand will increase substantially—but the increase is manageable. The analysis projects that electrifying the heat currently supplied by gas may double electricity demand during peak times, with demand growing at about 2% annually between now and 2050. However, Minnesota's electricity system successfully managed periods of similar growth in the 1990s and early 2000s. The amount and cost of peak demand growth can also be mitigated by a number of factors that were not fully evaluated in the modeling. Demand response programs that incentivize customers to use electricity off peak can reduce peak demand, as can more aggressive weatherization efforts and improved building codes. And an increase in electric vehicles charging overnight will spread electric system costs over a greater amount of sales, pushing rates down.

However, even without factoring these options into the base analysis, the study concluded that the downward pressure on rates due to increased sales outweighs the cost of additional electric system investments, resulting in declining electric rates in both scenarios.

We need a planned transition to clean heat. Geographically clustering electrification**—**and paring back the gas system in those areas**—**will help keep costs affordable in either scenario. It may be necessary to accelerate the depreciation of gas utility infrastructure in order to allow utilities to recover the costs of the investments that they have made, and investments they must continue to make to keep the gas system safe through the transition period. We also need policies to assist low- and moderate-income households and renters, who may otherwise have difficulty updating their heating systems. To ensure the transition is affordable and equitable, Minnesota should start planning today.

Like any modeling exercise, this study is necessarily imprecise. The modelers chose conservative assumptions. As discussed, the study does not include the cost of offsets the state would need to purchase to reach net zero in the scenario that includes RNG, it uses optimistic estimates of RNG availability, and it does not include measures that could mitigate peak electric load and its costs. It likely overestimates the cost of electric transmission and distribution investments. The base analysis does not consider thermal energy networks or targeted energy efficiency. A supplementary sensitivity analysis suggests that district energy systems powered by ground-source heat pumps have great potential to reduce peak electric demand, improve energy efficiency, and lower ratepayer costs.

These assumptions generally weight the conclusions against the Full Electrification scenario. But even with these conservative assumptions, the Full Electrification scenario appears to be significantly less expensive than the scenario that maximizes RNG.

This report provides new analysis that the Clean Heat Minnesota coalition hopes will inform utilities, regulators, policy makers, and Minnesotans about the pathways to eliminate greenhouse gas emissions from heating in our state. We must begin now to decarbonize Minnesota's buildings—and this study shows that we can.

We look forward to working together toward a state where everyone can heat, cook, and power their appliances with affordable, clean energy.

Sincerely,

Clean Heat Minnesota, Minnesota Decarbonization Analysis Steering Committee

Citizens Utility Board of Minnesota
Comunidades Organizado El Poder y La Acción Latina (COPAL)
Fresh Energy
Minnesota Center for Environmental Advocacy
Sierra Club North Star Chapter

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EXECUTIVE SUMMARY

The objective of this report is to help identify the most feasible, equitable, and cost-effective pathways for reducing emissions from Minnesota's natural gas distribution sector at a pace and magnitude consistent with Minnesota's greenhouse gas emission reduction goals. Decarbonization of the building sector—particularly in the residential building sector where emissions are increasing—is one of the main strategies established for meeting the state's goal of net-zero emissions by 2050. The primary source of emissions in the residential sector is natural gas used in home heating and appliances. For the commercial sector, emissions are generated from the use of oil and natural gas. For this reason, Synapse Energy Economics focused on residential and commercial energy end uses and the impacts that their decarbonization would have on the gas and electric systems, on costs to customers, and on health and environmental issues.

This report describes our analysis of two "book-end" scenarios that we developed to illustrate potential pathways to decarbonization: one to maximize building electrification and one to maximize the feasible use of alternative fuels.

- The **Full Electrification** scenario is characterized by high adoption of whole-building electrification. Nearly all the decarbonization measures are centered around electrification of building end uses.
- The **Electrification + Alternative Fuels** scenario is characterized by the use of renewable natural gas, based on an optimistic forecast of availability, to replace natural gas for major end uses in residential and commercial buildings. In addition, this scenario emphasizes increased adoption of dual-fuel heat pumps with fuel backup systems over all-electric heat pumps.

Key Findings

Our key findings are:

- To reach net-zero emissions by 2050, efficient heat pump sales must dramatically increase by 2030 in both the commercial and residential building sectors compared to current market trends. Compared to full electrification, cumulative building sector emissions are 9 percent higher in a scenario that combines alternative fuels with electrification (called the Electrification + Alternative Fuels scenario) due to the use of a limited supply of renewable natural gas for dual-fuel heat pump systems in later years.
- Under the Full Electrification scenario, the analysis shows system-wide electric peak loads increasing by 93 percent, while under the Electrification + Alternative Fuels we project that system-wide peak loads will increase by 72 percent. We expect Minnesota's electric grid would transition to winter-peaking around 2029 under the Full Electrification scenario, while the grid would not transition to winter-peaking under the

Electrification + Alternative Fuels scenario until around 2038. (In a separate sensitivity analysis, we also found that ground-source heat pumps and demand response measures can help mitigate the electric system costs and peak demand in the Full Electrification scenario.)

- Electric delivery rates under the Full Electrification case will be slightly lower than the rates under the Electrification + Alternative Fuels case. This analysis shows that the effect of the increased revenues due to building electrification is greater than the effect of the increased transmission and distribution investments due to building electrification.

- In both scenarios, customers who remain on the gas system are also expected to face higher rates and have higher annual gas bills, even with decreased fuel use per customer in the Electrification + Alternative Fuels scenario. We find that, on average over the next 20 years, all-electric homes in the Electrification + Alternative Fuels scenario will save an average of $540 per year on energy costs relative to non-electrified homes with gas heat. This is because gas prices are expected to rise as increasing amounts of renewable natural gas replaces traditional fossil gas. In the Full Electrification scenario, average energy bills over the next 20 years for an all-electric home will be roughly $190 lower per year than a non-electrified home with gas heat.

- Policies could be put in place to assist customers remaining on the gas system. This policy assistance will be critical, as those remaining are likely to be those with the least ability to choose to electrify and depart the gas system, such as low- and moderate-income customers and renters. Electrification programs could also target electrification to vulnerable customers, so they are not the last users of the gas system.

- Overall, the Full Electrification and Electrification + Alternative Fuels scenarios have relatively similar present-value equipment costs to customers, as both scenarios will require substantial adoption of new electrification and decarbonization technologies over the study period. (These costs do not reflect the potential discounts or incentives from utility, state, or federal programs, which could greatly reduce upfront costs of efficient electric equipment.)

- The Full Electrification case will cost between $13.3 to $14.6 billion dollars (roughly 25 percent) less than the Electrification + Alternative Fuels case in net-present-value terms. This total accounts for equipment costs, fuel supply costs, net electric sector costs, gas system costs, as well as environmental externalities.

It is important to note that this study is not intended to be precise in its estimates of technology adoption rates, energy consumption, and costs. Rather, the intent is to illustrate directionality and a range of possible futures.

Overall, the results point to the importance of intentional utility planning, for both electric and gas utilities, to ensure customer costs do not increase uncontrollably and to minimize the risk to the utilities, their shareholders, and ratepayers. Planning for changes in utility investment and financial models is preferable to the inequitable outcomes that could result from an unplanned and unmanaged transition.

Building Decarbonization Analysis

To evaluate different greenhouse gas emissions reduction pathways for Minnesota's residential and commercial building sectors, Synapse used its in-house stock turnover model, the Building Decarbonization Calculator, to model the energy consumption of space heating, water heating, cooking, and clothes drying systems in residential and commercial buildings. We forecasted energy use over time associated with various space heating, water heating, cooking, and drying system technologies. We also calculated the associated emissions impacts from the modeled changes in appliance market share and evaluated how various trajectories of heat pump installations can help meet greenhouse gas emissions reduction goals. Table 1 summarizes the key outcomes of our modeling results, focusing on the space heating end use.

Table 1. Market share, stock, and electricity consumption results for modeled scenarios

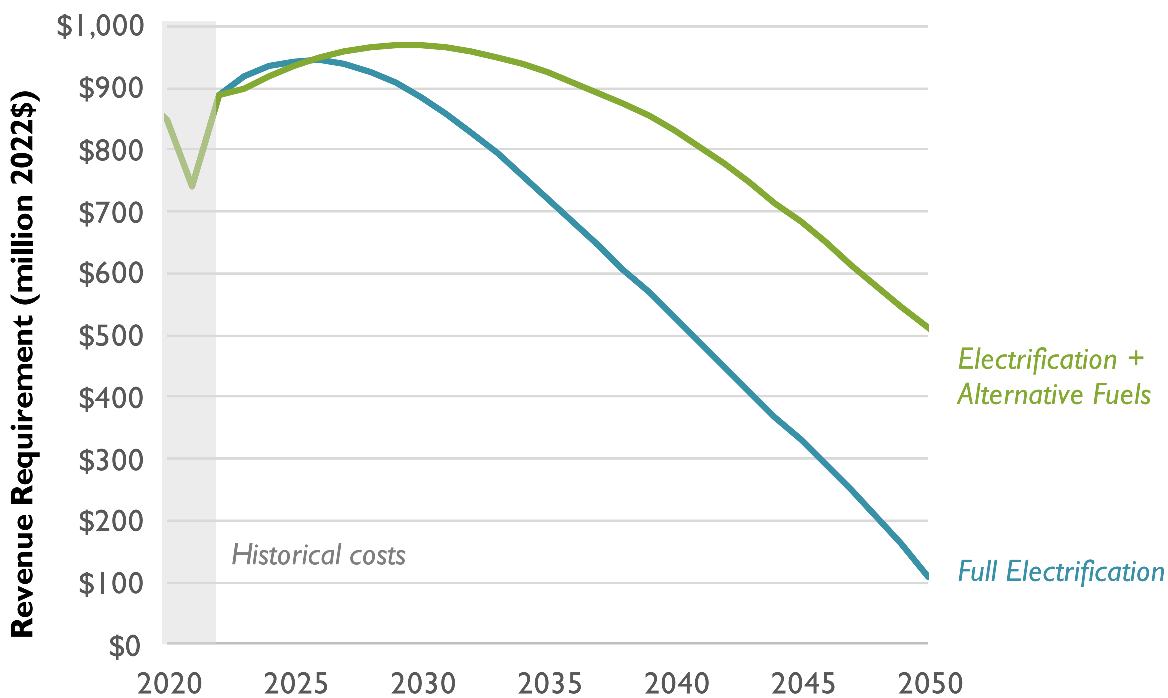
Metric	Full Electrification	Electrification + Alternative Fuels
All-electric heat pump share of residential space heat equipment sales in 2030	97% (approx. 110,000/yr)	50% (approx. 56,000/yr)
All-electric heat pump share of installed residential heating systems in 2050	91%	71%
Cumulative residential space heat pump early replacements	161,500	0
All-electric heat pump share of commercial space heat equipment sales in 2030	80%	43%
All-electric heat pump share of installed commercial heating systems in 2050	93%	75%
Cumulative amount of commercial floor area converted through heat pump early replacements	91 million square feet	0
Percent of homes in 2050 connected to gas infrastructure	0.2%	21%
Percent of commercial building square footage in 2050 connected to gas infrastructure	0.1%	19%
Residential and commercial electricity consumption from thermal loads across all end-uses in 2050	25.4 TWh	23.1 TWh

Gas System Impact Analysis

Based on the results of the building decarbonization analysis, Synapse used its in-house Gas Rate Model to analyze the gas customer and utility financial impacts of the two scenarios, focusing on the three largest gas utilities in Minnesota. The model allows us to test scenarios for different levels of investment and customer growth or decline, pipeline replacement programs, early retirements, stranded costs, and changes in depreciation rates. We used the model to project gas and electric utility rates for our two scenarios, assuming the utilities continue operating under a traditional gas-delivery business model and that they plan ahead so they can recover all invested capital, with a fair rate of return, as they transition to a decarbonized future.

We found that the residential and commercial revenue requirement for gas utilities by 2050 would be significantly lower under the Full Electrification scenario than under the Electrification + Alternative Fuels scenario. This is due to the accelerated depreciation under the Full Electrification scenario, as compared to the Electrification + Alternative Fuels scenario (Figure 1). The largest driver of the difference between the revenue requirements in the two cases is operations and maintenance costs: serving more customers over more miles of pipe requires more revenue.

Figure 1. Residential and commercial gas revenue requirement



In both scenarios, customers who remain on the gas system are also expected to face higher rates and have higher annual gas bills, even with decreased fuel use per customer in the Electrification + Alternative Fuels scenario.

Electric System Impact Analysis

The increased electrification of heating and other energy uses in buildings will impact the electricity system's peak load, and Minnesota's electric grid will likely transition to winter-peaking within the next decade or so. We projected these peak-load impacts due to building electrification through 2050 for the two scenarios analyzed (accounting for the impacts of the state's cold climate on heat pump efficiency). We estimated net incremental peak loads and the associated transmission and distribution investments under our scenarios beyond what would be expected under a baseline load forecast. Notably we used a conservative approach that likely overestimates necessary transmission and distribution investments because it does not consider any available system capacity headroom beyond the current peak loads available from the existing electric grid.

On a peak day, modeling shows both scenarios would have increased electricity demand as a result of heat pump space heating. In 2050, the peak load under the Electrification + Alternative Fuels scenario is 12 percent lower than the peak load under the Full Electrification scenario due to the higher adoption of dual-fuel heat pumps, which utilize natural gas backup under periods of extreme cold. In contrast, under the Full Electrification scenario, more heat pumps are backed up with electric resistance heating, which exacerbates the effect that extreme cold has on the electric grid.

Overall, we estimate increased demand will necessitate investments totaling approximately $2.6 billion in present value (PV) through 2050 under the Full Electrification scenario and $1 billion (PV) under the Electrification + Alternative Fuels scenario. These costs for these investments are more than covered by the increased electricity sales from electrification, however. This leads to projected electric delivery rates for both scenarios that are approximately 9 to 11 percent lower on average than the delivery rates expected for the baseline case. Further, we found that the rates under the Full Electrification case will be slightly lower than the rates under the Electrification + Alternative Fuels case. Table 2 compares levelized electricity delivery rates by scenario through the study period.

Table 2. Comparison of levelized electricity delivery rates by scenario (cents/kWh)

	Baseline	Increased revenue due to electrification	Net incremental T&D costs due to electrification	Total delivery rates	Rate change (% of baseline)
Full Electrification	6.66	-1.12	0.35	5.89	-11.6%
Electrification + Alternative Fuels	6.66	-0.74	0.16	6.08	-8.7%

Cost Analyses

Resource Cost Analysis

Synapse investigated the upfront costs customers would pay for new electrification equipment (e.g., heat pumps) and new fossil fuel equipment (e.g., new furnaces) under each decarbonization scenario. Overall, the Full Electrification and Electrification + Alternative Fuels scenarios have relatively similar present-value equipment costs, as both scenarios will require substantial adoption of new electrification and decarbonization technologies. In present-value terms, the resource costs in the Full Electrification case total $8.65 billion, compared to $8.40 billion for the Electrification + Alternative Fuels case. The

Electrification + Alternative Fuels case has slightly lower total capital costs overall compared to the Full Electrification case. This is primarily because it relies more heavily on a hybrid approach with gas water heaters and dual-fuel heat pumps retaining existing backup systems, rather than an approach with HPWHs, more expensive whole-home heat pump options that require larger size heat pumps, early retirement of fossil fuel appliances, and more electric panel upgrades. These costs do not reflect the potential to reduce gas system costs in the electrification cases, nor do they include discounts or incentives from utility, state, or federal programs. In addition, this does not include costs from further emissions reduction activities to reach net-zero in the buildings sector in the Electrification + Alternative Fuels case, not modeled in this analysis.

Customer Bill Analysis

Synapse conducted an illustrative analysis of residential energy bills under both scenarios. We conducted this analysis of annual bills through 2050 for residential customers in Minnesota living in three types of homes: an all-electric home, a mixed-fuel home with partially electrified space heating, and a mixed-fuel home using only gas for space heating.

Our residential bill analysis estimates the total energy bills for residential customers between 2023 and 2050. In the Full Electrification scenario, average energy bills over the next 20 years for an all-electric home will be roughly $190 lower per year than a non-electrified home with gas heat. In the Electrification + Alternative Fuels scenario, all-electric homes will save an average of $540 per year on energy costs compared to non-electrified homes with gas heat, due to increasing gas prices as RNG replaces pipeline gas over time.

Total Costs

Synapse estimated the total costs for the system under both modeled scenarios, accounting for equipment costs, fuel supply costs, net electric sector costs, gas system costs, as well as environmental externalities. Synapse finds that the Full Electrification case will cost between $13.3 to $14.6 billion dollars (roughly 25 percent) less than the Electrification + Alternative Fuels case in net-present-value terms. While Synapse analysis shows that the net electric sector costs (including transmission, distribution, and supply) relative to a business-as-usual scenario are 45 percent higher in the Full Electrification case than the Electrification + Alternative Fuels case, gas system revenue requirements and fuel costs are substantially lower. In fact, gas system costs are 22 to 31 percent higher in the Electrification + Alternative Fuels case, and fuel costs are more than double in the Electrification + Alternative Fuels case relative to the Full Electrification case. Environmental externalities are $2 to $5 million higher in NPV-terms in the Electrification + Alternative Fuels case due to the increased combustion of fossil fuels over the analysis period.

Other Technologies

Synapse performed sensitivity analysis on three additional decarbonization strategies that could greatly mitigate increased demand due to electrification, particularly in winter:

Ground-source heat pumps are not commonly used due to their higher upfront cost. Nevertheless, we found that a higher market share of GSHPs could lower projected peak load impacts by roughly 6 to 10 percent lower through 2050 (compared to the Full Electrification case).

Demand response measures can help reduce winter peak loads. These include smart thermostats for space heating, direct load controls of storage water heaters, EV charging and electric batteries, alternative rate designs, and others. We estimated the total winter peak load reductions from demand response for space and water heating range from 1 GW to 3 GW, representing 4 percent to 11 percent of the total system load.

Networked geothermal systems—ground-source heat pumps combined with district energy to create highly efficient, neighborhood-scale heating and cooling systems—can contribute to decarbonization efforts, provide a potential avenue for gas utilities to re-use existing assets such as rights-of-way as the gas system winds down, and preserve pipeline jobs.

Environmental Impact

Burning pipeline gas worsens both outdoor air quality (when furnaces, boilers, and hot water heaters are vented outside) and indoor air quality (due to leaked and combusted gas in enclosed spaces). We conducted quantitative analysis to estimate the outdoor air pollution health impacts and benefits of reduced gas usage in residences under the two scenarios. Overall, the analysis shows meaningful potential for decarbonization efforts to produce positive health impacts based on reductions in outdoor air pollution. For indoor air quality impacts, we conducted a literature review and qualitative analysis of the impacts of indoor levels of pollutants. These studies demonstrate that indoor levels of pollutants may be two to five times—and occasionally more than 100 times—higher than outdoor levels. Importantly, the detrimental effects of air pollution disproportionately impact environmental justice communities. We recommend additional research on natural gas use in buildings to facilitate future estimates of the additional health benefits and savings that would result from either of the two scenarios modeled in this analysis.

1. INTRODUCTION AND BACKGROUND

1.1 Minnesota Climate Targets

The legislature of the state of Minnesota addressed greenhouse gas emission levels in 2007 with the promulgation of the *Next Generation Energy Act* (NGEA). The NGEA targeted a reduction of greenhouse gas emissions by 30 percent by 2025 and 80 percent by 2050, from a 2005 baseline.[1] In 2023, the legislature codified updated targets into law. Section 216H.02 now states that "it is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing greenhouse gas emissions by at least the following amounts, compared with the level of emissions in 2005: (1) 15 percent by 2015; (2) 30 percent by 2025; (3) 50 percent by 2030; and (4) to net zero by 2050."[2]

To guide the response, the Executive branch's Climate Change Subcabinet created the Minnesota Climate Action Framework with input from the 11 tribal sovereign nations in the state of Minnesota and the Governor's Advisory Council on Climate Change. The framework sets a vision for how the state will address and prepare for climate change. It identifies immediate, near-term actions to achieve the long-term goal of a carbon-neutral, resilient, and equitable future.

The framework identifies actions to achieve the targets established by statute, to reduce greenhouse gas emissions by 50 percent by 2030 and to achieve net-zero emissions by 2050. Priority actions include the reduction of emissions related to heating and cooling homes and businesses by exploring and evaluating new regulatory and policy options, such as a clean thermal standard and incentive programs.[3] This also includes maximizing emission reductions through the implementation of the *Energy Conservation Optimization Act* and the *Natural Gas Innovation Act*.

1.2 Minnesota Greenhouse Gas Emissions

In 2020,[4] total greenhouse gas emissions in Minnesota totaled 137 million tons of carbon dioxide equivalent (CO2e), a 23 percent decrease from 2005.[5] To meet the state's 2030 target set by the Climate

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[1] Minnesota Next Generation Energy Act of 2007. Available at: https://www.revisor.mn.gov/bills/text.php?number=SF145&version=0&session_year=2007&session_number=0.

[2] Minnesota Statutes 2022, section 216H.02, subdivision 1. Available at: https://www.revisor.mn.gov/laws/2023/0/60/laws.12.61.0#laws.12.61.0.

[3] Minnesota Climate Action Framework, page 50. Available at: https://climate.state.mn.us/sites/climate-action/files/Climate%20Action%20Framework.pdf.

[4] 2020 data reflects the impacts of the COVID-19 Pandemic; thus, the report notes its caution regarding interpretation of trends with a 2020 endpoint.

[5] Minnesota Pollution Control Agency and Department of Commerce. January 2023. *Greenhouse Gas Emissions in Minnesota 2005-2020.* Page 8. Available at: https://www.pca.state.mn.us/sites/default/files/lraq-2sy23.pdf.

Action Framework, the state must reduce emissions by 48.5 million tons CO2e, a 35 percent reduction from 2020 emissions levels.[6] Residential and commercial buildings generate emissions from fossil-fuel combustion and are the source of a significant fraction of total greenhouse gas emissions in the state. The residential sector is of particular interest since emissions from residential buildings have increased 14 percent relative to 2005. The primary source of emissions in this sector is natural gas used in home heating and appliances, [7] stemming from the fact that most homes in Minnesota (approximately 66 percent) heat with natural gas.[8] The commercial sector emissions are decreasing primarily due to declining use of oil and some reduction in natural gas use (with a 22 percent decrease in emissions from 2005 levels).[9] Reducing and decarbonizing the energy used in residential and commercial buildings is thus a key strategy for achieving the state's climate targets.

1.3 Objective of the Report

A coalition of stakeholders commissioned Synapse Energy Economics (Synapse) to analyze approaches for reducing emissions from Minnesota's gas distribution at a pace and magnitude consistent with Minnesota's greenhouse gas emission reduction goals. The objective of this resulting report is to help identify the most feasible, equitable, and cost-effective pathways for achieving those goals.

We began by developing two "book-end" scenarios that illustrate potential pathways to decarbonization, the first to maximize building electrification and the second to maximize the use of alternative fuels. These bookends provide a boundary for a range of possible futures. We began the analysis by evaluating the impact of changes in heat pump market share on the installed stock of space-heating, water-heating, and cooking equipment, and the resulting impact on energy consumption and its associated greenhouse gas emissions (Chapter 2). We used this information to estimate the impact on the gas and electricity systems (Chapter 3 and Chapter 4). We analyzed the impact on the gas distribution utility from both a consumer and investor perspective. Then we estimated the change in total winter peak load driven by the increase in the use of electricity to power appliances for space heating, water heating, and cooking. This analysis is supplemented by deep dives into the impact of three potential strategies to support decarbonization: increased use of ground-source heat pumps (GSHP), demand response activities, and network geothermal systems (Chapter 7).

We used the results of the scenario analysis to calculate the total equipment cost for residential and commercial customers (Chapter 5) and to develop an illustrative energy bill for residential customers, under both scenarios. The cost analysis culminated by presenting the total cost for the system,

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[6] Kohlasch, Frank. "Progress and opportunities to address climate change: A summary of Minnesota's greenhouse gas emissions." February 20, 2024. Available at: https://www.house.mn.gov/comm/docs/BL-NZIVxkUSKjRhQPe6J5w.pdf

[7] MN Pollution Control Agency, page 14.

[8] U.S. Energy Information Administration (EIA). "Minnesota State Energy Profile." Available at: https://www.eia.gov/state/print.php?sid=MN.

[9] MN Pollution Control Agency, page 15.

accounting for equipment, fuel supply, electric sector impacts, and the gas system impacts, plus the cost of environmental externalities (Chapter 6). And finally, we discuss health and environmental impacts through an equity lens (Chapter 8).

This study is not intended to be precise in its estimates of technology adoption rates, energy consumption, and costs. (We expanded upon limitations to the analysis in the body of the report.) Instead, the intent is to illustrate directionality and a range of possible futures.

2. BUILDING DECARBONIZATION ANALYSIS

2.1 Scenario Analysis

Synapse conducted an analysis of the energy and emissions impacts of various building decarbonization strategies for gas-consuming end uses for Minnesota. We analyzed two decarbonization scenarios that demonstrate the impacts of different resource mixes in the residential and commercial sectors towards achieving Minnesota's 2050 greenhouse gas emissions targets. These scenarios present two possible futures given certain assumptions of market share and equipment stock turnover. The scenarios were deliberately chosen to be bookends: maximizing electrification and maximizing alternative fuels. Thus, these provide a boundary within which a range of possible futures and decarbonization strategies lie.

Table 3 summarizes the key assumptions for each scenario.

- **Full Electrification Scenario** is a scenario characterized by high adoption of whole-building electrification. Nearly all of the decarbonization measures involve electrification of building end uses: air-source heat pumps (ASHP), ground-source heat pumps (GSHP), heat pump water heaters (HPWH), and electric cooking and drying technologies. These measures are supported by energy efficiency and weatherization efforts. To model full electrification, Synapse assumed all new heat pump sales in this scenario would be all-electric cold-climate heat pumps (ccASHP) with electric resistance backup at very low temperatures, instead of fuel backup systems. Throughout the report, we refer to these as 'all-electric ASHPs'.
- **Electrification + Alternative Fuels Scenario** is a scenario with high potential for renewable natural gas (RNG) to replace natural gas for major end uses in residential and commercial buildings.[10] For buildings heated with non-natural gas fuels (e.g., propane, fuel oil) we assumed a similar level of electrification as in the Full Electrification Scenario. However, this scenario emphasizes increased adoption of dual-fuel heat pumps over all-electric heat pumps for buildings heating with natural gas. In this study, "dual-fuel heat pumps" refers to heat pumps that do not serve the full heating load and are integrated with a fossil fuel backup heating system. We assumed that the majority of remaining natural-gas-heated buildings would retain their other natural gas end-use appliances (i.e., water heating,

[10] We did not model hydrogen blending in the Electrification + Alternative Fuels scenario, under the assumption that hydrogen would primarily be directed towards meeting hard-to-electrify demand from the industrial and heavy-duty transportation sectors.

cooking, and drying). As with the Full Electrification Scenario, these measures are also supported by weatherization and energy efficiency efforts.

Table 3. Comparison of key input assumptions for Full Electrification and Electrification + Alternative Fuels scenarios

	Full Electrification Scenario	Electrification + Alternative Fuels Scenario
Weatherization and building shell assumptions	EIA Annual Energy Outlook (AEO) 2023[11]	EIA AEO 2023
Dual-fuel heat pumps	No new dual-fuel heat pumps with fossil fuel backup systems modeled	Dual-fuel and all-electric ASHPs replacing natural gas systems reach 50/50 sales split in 2042
Ground-source heat pumps	Buildings heating with gas, propane, electric resistance, or fuel oil that switch to heat pumps are assumed to install ASHPs 95% of the time, and GSHPs 5% of the time	Natural Gas: No GSHP fuel-switching Propane, electric resistance, and fuel oil: same as Full Electrification scenario (95% ASHPs, 5% GSHPs)
Early replacements	Early replacements of customer appliances phased in from 2045–2050 to eliminate fossil fuel systems	None explicitly modeled
Water heating, cooking, and drying	Heat pump water heaters replace fossil-fuel-based water heaters. Efficient electric appliances replace fossil-fuel-based appliances.	Natural Gas: Most households that stay on gas system keep gas for water heating, cooking, and drying Propane, electric resistance, and fuel oil: same as Full Electrification Scenario
RNG	None	RNG blended into natural gas system starting in 2025, fully replaces natural gas by 2050 to serve remaining natural gas consumption

2.2 Modeling Methodology

2.2.1 Building Decarbonization Calculator

To evaluate different greenhouse gas emissions reduction pathways for Minnesota's building sector, Synapse used its Building Decarbonization Calculator (BDC). The BDC is a tool for modeling the energy consumption of space heating, water heating, cooking, and clothes drying systems in residential and commercial buildings in jurisdictions throughout the United States. The BDC quantifies how accelerating the adoption of new technologies impacts greenhouse gas emissions and electricity consumption. The model uses a stock turnover framework to forecast energy use over time associated with various space heating, water heating, cooking, and drying system technologies. It also calculates the associated emissions impacts from the modeled changes in appliance market share and evaluates how various trajectories of heat pump installations can help meet greenhouse gas emissions reduction goals.

[11] Based on EIA AEO 2023, we assume annual efficiency improvements of .06 to .08 percent for building shells.

The BDC utilizes state-specific data on existing buildings from sources such as U.S. Census Bureau's American Community Survey,[12] along with the U.S. Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) and Commercial Buildings Energy Consumption Surveys (CBECS) to characterize current building heating system stocks. Synapse also used Minnesota-specific residential and commercial equipment data from the Center for Energy and Environment's 2019 Energy Efficiency Potential Study and the State of Minnesota's parcel property database.[13,14] The BDC accounts for improvements in appliance efficiency, appliance survival rates over time, and new construction buildings over the study period.[15] To calibrate the model, Synapse compared the resulting energy consumption outputs by fuel type for the baseline year against actual historical data from EIA's State Energy Data Systems (SEDS).[16] For future years, the BDC uses technology adoption curves to estimate annual system sales by fuel type, sector, and end use.

2.3 Key Assumptions

For detailed assumptions, see Technical Appendix A. Building Decarbonization Model Assumptions.

2.3.1 Residential Buildings

There are currently an estimated 2.2 million residential households in Minnesota.[17] Synapse assumes this number will grow at the same rate as population, which is forecasted to grow by 0.55 percent annually on average between now and 2050.[18] As shown in Figure 2, natural gas is currently the primary space and water heating fuel in Minnesota, followed by electric resistance and propane. Heat pumps only account for 3 percent of space heating stock and less than 1 percent of water heating stock. Roughly two-thirds of homes use natural gas cooking equipment, with the remaining third using electric cooking appliances. The reverse is true for clothes drying: two-thirds of households with in-unit laundry

[12] U.S. Census Bureau. 2021. *2021 American Community Survey 1-Year Estimates*. House Heating Fuel. Table B25040. Available at: https://data.census.gov/cedsci/table?q=residential%20heating%20fuel&g=0100000US%2404000%24001_0400000US41&tid=ACSDT5Y2020.B25040.

[13] Center for Energy and Environment (CEE). 2019. *Minnesota Energy Efficiency Potential Study: 2020-2029, Appendix J: Residential Buildings Primary Data Collection Report*. Prepared for the Minnesota Department of Commerce, Division of Energy Resources. Available at: https://www.mncee.org/sites/default/files/2021-06/Appendix-J_Residential-Primary-Data-Collection_2019-03-27.pdf.

[14] Minnesota Geospatial Information Office. "Land Ownership: Parcels." Updated 2023. Available at: https://www.mngeo.state.mn.us/chouse/land_own_property.html.

[15] New construction stock growth is based on state population growth. See: University of Virginia Weldon Cooper Center, Demographics Research Group. (2018). National Population Projections. Retrieved from https://demographics.coopercenter.org/national-population-projections.

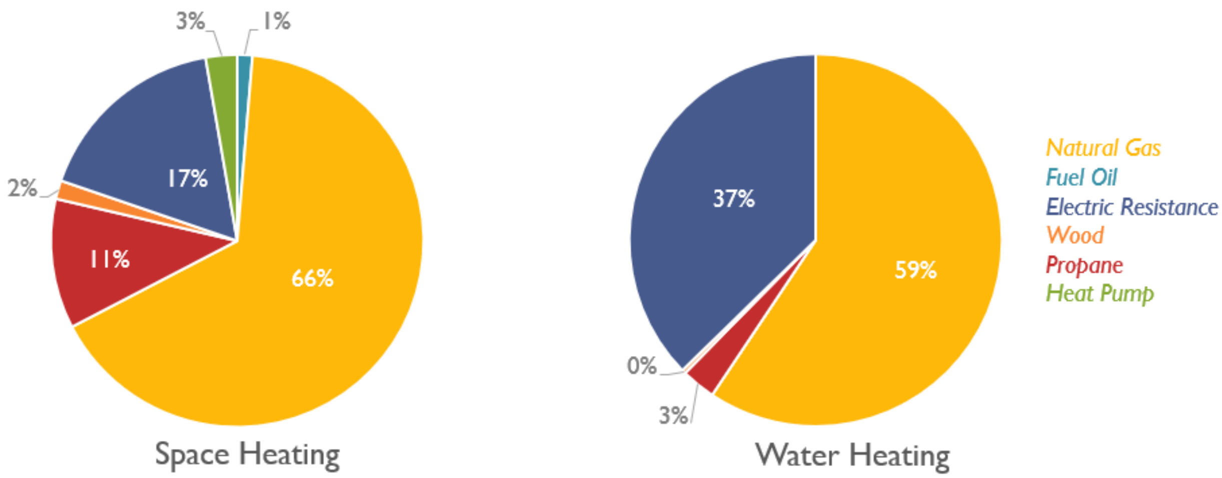
[16] U.S. EIA. 2023. *State Energy Data System (SEDS)*. Available at: https://www.eia.gov/state/seds/.

[17] U.S. Census Bureau. 2021. *2021 American Community Survey 1-Year Estimates*. House Heating Fuel. Table DPO5. Available at: https://data.census.gov/table?q=DP05&g=040XX00US09&tid=ACSDP1Y2021.DP05.

[18] University of Virginia Weldon Cooper Center, Demographics Research Group. 2018. *National Population Projections*. Available at: https://demographics.coopercenter.org/national-population-projections.

use electric dryers, while the remaining third uses gas for clothes drying. Less than 5 percent of homes use propane for cooking or clothes drying.[19,20] Among all gas end uses, space heating and water heating account for 78 percent and 19 percent of residential gas consumption, respectively.[21]

Figure 2. Residential space and water heating equipment stock by fuel (% of households)



Source: U.S. Energy Information Administration. 2020 Residential Energy Consumption Survey, 2023, U.S. Census Bureau American Community Survey, Minnesota Energy Efficiency Potential Study, 2019.

2.3.2 Commercial Buildings

There is roughly 2.3 billion square feet of commercial floor area in Minnesota. Similar to the residential sector, natural gas is the primary source for space heating. Figure 3 shows that two-thirds of commercial floor space is heated by gas, while the remaining third heats with electric resistance (14 percent), fuel oil (7 percent), heat pumps (5 percent), and propane (4 percent). Roughly half of commercial buildings use gas for water heating, and slightly less than half (45 percent) use electric resistance equipment. Less than 5 percent of commercial square footage uses propane or heat pumps to serve water heating load. We estimate that two-thirds of commercial cooking equipment uses gas, with the remaining third using electricity. [22]

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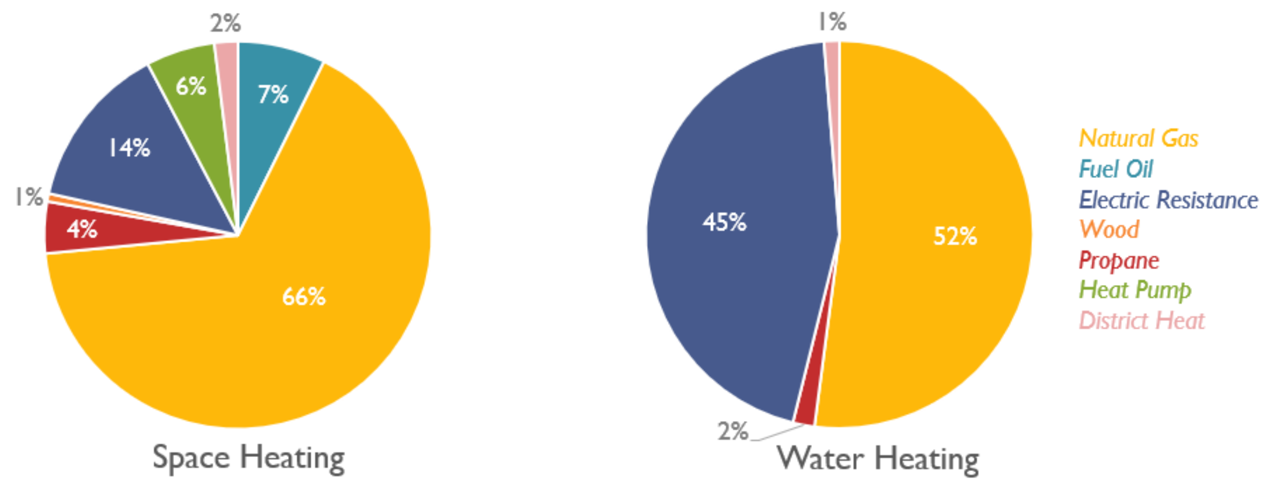
[19] Center for Energy and Environment (CEE). 2019. *Minnesota Energy Efficiency Potential Study: 2020-2029, Appendix J: Residential Buildings Primary Data Collection Report*. Prepared for the Minnesota Department of Commerce, Division of Energy Resources. Available at: https://www.mncee.org/sites/default/files/2021-06/Appendix-J_Residential-Primary-Data-Collection_2019-03-27.pdf.

[20] U.S. EIA. 2023. *2020 Residential Energy Consumption Survey (RECS)*. Available at: https://www.eia.gov/consumption/residential/data/2020/.

[21] U.S. EIA. 2023. *2020 Residential Energy Consumption Survey (RECS)*. Available at: https://www.eia.gov/consumption/residential/data/2020/.

[22] U.S. EIA. 2022. *2018 Commercial Building Energy Consumption Survey (CBECS)*. Available at: https://www.eia.gov/consumption/commercial/data/2018/.

Figure 3. Commercial space and water heating stock by fuel (% of building square feet)



Source: U.S. Energy Information Administration 2018 Commercial Buildings Energy Consumption Survey, 2022.

2.3.3 Technology Assumptions

2.3.3.1 Air-source heat pumps

Electric heat pumps are versatile and energy efficient technologies that can provide space heating and cooling as well as water heating.[23] Heat pumps use compression cycles to move heat in or out of a building for space heating and cooling. The efficiency of heat pumps is represented by the coefficient of performance (COP), defined as the ratio of useful heating or cooling to the total energy input. Because heat pumps transfer heat instead of generating it, the efficiencies of heat pumps can be greater than 100 percent and typically exceed 250 percent (represented by a COP of 2.5) for heating and 400 percent (or a COP of 4) for cooling on average. The temperature of the outdoor air or other heat reservoirs affects the efficiency of heat pumps. Most heat pumps installed today for space heating are ASHPs which extract heat from the outdoors. Thus, those heat pumps perform most efficiently when outdoor temperatures are high and are less efficient when outdoor temperatures are very low.

New, readily available heat pump technologies such as cold-climate heat pumps are already capable of producing comfortable heat at below zero degrees.[24] However, there are still concerns about the impact of heat pumps on electrical grid winter peak loads, especially for very cold climates such as Minnesota. To mitigate this impact, states such as Minnesota may consider a dual-fuel heat pump approach. In this

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[23] This study did not analyze gas heat pumps due to their high costs and limited efficacy in reducing emissions from fuel combustion.

[24] Center for Energy and Environment. 2017. *Cold Climate Air Source Heat Pump.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources. Available at: https://www.mncee.org/sites/default/files/report-files/cold-climate_0.pdf, and Ben Shoenbauer et al., *Field Assessment of Ducted and Ductless Cold Climate Air Source Heat Pumps*, Center for Energy and Environment (2018), https://www.mncee.org/field-assessment-ducted-and-ductless-cold-climate-air-source-heat-pumps.

approach, heat pumps are used alongside fossil-fuel-based backup or supplemental heating systems. Compared to a whole-home heat pump without any fossil-fuel-based backup heating, these dual-fuel systems can reduce the majority of natural gas used for space heating and reduce electric peak demands during the coldest winter peak days or hours.

As mentioned above, we analyzed two types of heat pumps: all-electric heat pumps with electric resistance backup heating that meet the entire building space heating load without any fossil fuel backup heating; and dual-fuel heat pump systems that rely on existing or new gas heating systems during the coldest hours or days during the winter season. Our modeling approaches for these two types of heat pumps systems are as follows:

- All-electric heat pumps: Minnesota's winter climate with the coldest temperatures below negative 15 to 25 degrees Fahrenheit typically requires a backup electric resistance heater even for ccASHPs. We assumed that an all-electric ccASHP operates without any support of electric resistance heating down to 5 degrees and the electric resistance heater supplements the heat pump down to negative 15 degrees,[25] below which the heat pumps completely switch over to the electric resistance heater.
- Dual-fuel heat pumps: we determined the use of the gas backup system for a dual-fuel heat pump as a share of the total heating demand based on the *switchover temperature,* the threshold temperature at which the backup heating system is used instead of the heat pump. We assumed a switchover temperature of 15 degrees Fahrenheit.[26] Based on this switchover temperature, we calculated that 71 percent of annual heating loads will be served by heat pumps, and 29 percent would be served by the backup gas system.

For both heat pump systems, we developed COP values for heat pumps based on field evaluation studies of heat pumps and Minnesota-specific climate data.[27] We estimated that COP values range from 2.2 to 3.0 with the differences affected by the type of heat pumps (i.e., ducted vs. non-ducted) and the type of building (i.e., residential vs. commercial). We further assumed gradual efficiency improvements for heat pumps over time due to the potential technology improvement based on the National Renewable Energy Laboratory's (NREL) COP forecasts.[28] Technical Appendix A. provides details of these assumptions.

[25] Ibid.

[26] We assumed a 15-degree Fahrenheit cutover point, a higher temperature, so that heat pumps can be sized smaller and rely on the gas backup.

[27] Cadmus. 2016. *Ductless Mini-Split Heat Pump Impact Evaluation*. Available at: http://www.ripuc.ri.gov/eventsactions/docket/4755-TRM-DMSHP%20Evaluation%20Report%2012-30-2016.pdf, and Cadmus. 2022. *Residential ccASHP Building Electrification Study*. Available at: https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/PPSER/Program-Evaluation/Residential-ccASHP-Building-Electrification-StudyAugust-2022.pdf

[28] Jadun, P., et al. et al. 2017. *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050.* National Renewable Energy Laboratory. Available at: https://www.nrel.gov/analysis/electrification-futures.html.

2.3.3.2 Ground-source heat pumps

GSHPs are a less common type of heat pump in the United States. In comparison to ASHPs, GSHPs use the relatively constant temperature of the earth or groundwater as the heat reservoir instead of the outside air. Because ground temperatures are warmer than the outside air in winter and cooler than the air in the summer, a GSHP is highly efficient year-round. We assumed a GSHP COP of 3.43 for our building decarbonization analysis based on a 2016 study conducted by University of Minnesota's Cold Climate Housing Program.[29] However, the installation costs of a GSHP are often substantially more expensive than a similarly sized ASHP system because GSHPs require installation of the ground loops in addition to the building HVAC equipment. We assume that the majority of heat pumps installed in Minnesota will be ASHP and 5 percent will be GSHP, based on the share of ASHPs and GSHPs projected through 2029 as part of the Minnesota Energy Efficiency Potential Study.[30] See Section 7.1 for a sensitivity analysis and discussion of the impacts of GSHPs.

2.3.3.3 Heat pump water heaters

Similar to heat pumps for space heating, we developed average annual COP values for residential HPWHs based on several data sources. The primary source is a national study by Natural Resources Defense Council (NRDC) and Ecotope, which estimated average COP values for residential HPWHs in 50 states for various locations in a residential house (e.g., basement, closet, garage).[31] We then adjusted the HPWH COP values to reflect technology improvements since the study was conducted in 2016, based on current efficiency ratings for HPWHs. Finally, we developed projections of HPWH COP improvement over time using NREL's COP forecasts for HPWH in its Electrification Futures Study. For commercial HPWHs, we assumed the same COP as used for residential HPWHs.

2.3.3.4 Cooking and drying measure assumptions

To model the electrification of gas cooking, we assumed that electric cooktops and ovens replace gas appliances over time. Efficiencies of cooking equipment used in our analysis are presented in Technical Appendix A. While we derived these efficiencies for residential cooking equipment, we assumed the same efficiencies for commercial cooking equipment.

For the electrification of clothes drying, we assumed that efficient electric dryers replace gas dryers in residential buildings. The Technical Appendix provides the efficiencies of clothes dryers used in our

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[29] University of Minnesota, Cold Climate Housing Program. 2016. *Residential Ground Source Heat Pump Study*. prepared for Minnesota Department of Commerce. Available at: https://mn.gov/commerce-stat/pdfs/card-residential-gound-source-heat-pump-study.pdf.

[30] Center for Energy and Environment (CEE). 2019. *Minnesota Energy Efficiency Potential Study: 2020-2029, Appendix A: Methodology and Data Sources.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources. Available at: https://www.mncee.org/sites/default/files/2021-06/Appendix-A_Methodology-and-Data-Sources_2019-03-27_FINAL.pdf.

[31] National Resource Defense Council. November 2016. "NRDC/Ecotope Heat Pump Water Heater Performance Data." Available at: https://www.nrdc.org/resources/nrdc-ecotope-heat-pump-water-heater-performance-data.

study. We did not model high adoption of heat pump dryers, because heat pump dryers are substantially more expensive than standard efficient electric dryers.

We did not explicitly model commercial drying consumption. The EIA does not report specific data on commercial dryer usage because it contributes less than 5 percent to total gas consumption. Instead, EIA reports an "Other" category that includes this end use along with multiple others. To account for gas consumption used for drying, we scaled up the total results to align with historical consumption data from EIA.

2.3.4 Energy Efficiency Assumptions

To capture the benefits of weatherization, we modeled space heating load reductions over time based on EIA's building shell improvement projections from the 2023 Annual Energy Outlook (AEO 2023). EIA estimates that by 2050 residential buildings will consume 18 percent less energy for space heating on average relative to a 2020 baseline. For commercial buildings, EIA projects space heating energy savings of 23 percent relative to a 2018 baseline by 2050.[32]

2.3.5 Low-Carbon Fuels Assumptions

RNG is methane gas produced through the anaerobic digestion or thermal gasification of biogenic feedstocks. RNG can be produced from a variety of feedstocks, including organic waste (e.g., food waste, manure, agricultural residues), energy crops (i.e., crops grown for the production of RNG), and non-biogenic waste (e.g., construction debris). The potential for RNG use in building decarbonization is limited by both the availability and cost of feedstocks and competing demand from other sectors such as transportation, electric generation, and industry. A 2019 study by the consulting firm ICF International estimated RNG production potential in 2040 based on assumptions about feedstock availability and utilization.[33] ICF estimates that 751–2,074 trillion Btu of RNG will be available in the western United States in 2040 from landfill gas, animal manure, water resource recovery facilities, food waste, agricultural residues, forest residues, energy crops, and municipal solid waste.[34] Even under the optimistic scenarios projected by ICF, this potential RNG supply in 2040 would meet only 9–25 percent of the current gas demand in the western United States in 2021. Costs presented for RNG range from approximately $8 to $50 per MMBtu (in 2022 dollars), depending on the feedstock and potential, which is roughly 3 to 14 times more costly than the current market price for natural gas.[35]

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[32] Assumed annual efficiency improvements of .06 to .08 percent for building shells, based on EIA AEO 2023.

[33] ICF International. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. Prepared for the American Gas Foundation. Available at: https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

[34] Western U.S. includes Mountain, West North Central, West South Central, Mountain, and Pacific regions.

[35] U.S. EIA. *Annual Energy Outlook 2023*. Table 13: Natural Gas Supply, Disposition and Prices, Henry Hub Spot Price. Available at: https://www.eia.gov/outlooks/aeo/data/browser/.

To estimate the amount of RNG available to replace the current gas usage in the building sector in Minnesota, we first assumed that Minnesota will have access to a portion of total RNG produced in the western United States proportionate to the amount of natural gas consumed in the state relative to the western United States as a whole. To account for higher demand from hard-to-electrify end uses in the industrial sector, we assessed the quantity of specific industrial end-use segments (e.g., process heating) that require high temperatures, which are harder to electrify.[36,37] Based on this assessment, we allocated 60 percent of Minnesota's RNG potential to the industrial sector and 40 percent to be used in residential and commercial buildings. For the Electrification + Alternative Fuels scenario, we used ICF's High RNG potential as an optimistic estimate of RNG availability in 2040. This results in approximately 40 Tbtu of RNG per year available to Minnesota's residential and commercial sectors in 2040. This represents only 16 percent of Minnesota's residential and commercial sectors natural gas consumption (241 Tbtu) in 2021.[38]

Table 4. RNG potential

Sector	% share of RNG potential	Low RNG Case *(Tbtu/year)*	High RNG Case *(Tbtu/year)*
Residential and Commercial	40%	14.4	39.9
Industrial	60%	18.1	59.9
Total	**100%**	**36.1**	**99.9**

Based on these estimates, we developed RNG supply curves that reflect the potential pace of resource growth through 2040. Today, the majority of RNG produced is produced via anaerobic digestion at landfill gas facilities.[39] We assumed that landfill gas sources will be used first to produce RNG and sold in the RNG market, followed by other anaerobic digestion feedstocks (animal manure, wastewater recovery, and food waste). We assumed RNG produced via thermal gasification of feedstocks will not start to come online until 2030, reflecting the nascent nature of this technology.

In this study, we allocated RNG to natural gas end uses. We assumed propane and fuel oil end uses would electrify. We assumed that for the Electrification + Alternatives Fuels scenario RNG will be used for space heating, hot water heating, cooking, and clothes drying for homes and commercial buildings. For buildings that electrify space heating by adopting electric whole-building heat pumps, we assumed that other end uses will also be electrified. We assumed that new construction follows the same

36 MnTAP. 2010. *Energy Conservation Market Analysis.* Available at: http://www.mntap.umn.edu/wp-content/uploads/simple-file-list/Publications/Source/MnTAP-Energy-Conservation-Market-Analysis.pdf.

37 The current amount of natural gas used for transportation in Minnesota is very small compared to industrial and building sector consumption, and thus we did not account for RNG allocated for use in the transportation sector.

38 U.S. EIA. 2023. *Natural Gas Consumption by End Use*. Available at: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SLA_a.htm.

39 ICF International. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. Prepared for the American Gas Foundation. Available at: https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

trajectory in both scenarios, recognizing the increasing prevalence of all-electric new buildings and building codes requiring electric construction.

The emissions reduction potential of RNG depends on the feedstock from which it is produced. For this analysis we used lifecycle emissions factors for RNG based on California's Low Carbon Fuel Standard lifecycle carbon intensities, adjusted for pipeline compression.[40,41] RNG produced from animal manure has the greatest emissions reduction potential relative to combustion of traditional fossil gas. Some of the more plentiful feedstocks, such as RNG produced from landfill gas and water resource recovery facilities, have positive lifecycle emissions factors and lower emissions reduction potential. Synapse calculated a weighted average emissions rate across all RNG feedstocks to model the emissions from RNG blending over time.

2.4 Results

Table 5 summarizes the key outcomes of our modeling results with a focus on the space heating end use. In the Full Electrification case, all-electric heat pumps make up a high fraction of residential and commercial space heat equipment sales by 2030 and nearly all installed space heating equipment in 2050. In the Electrification + Alternative Fuels case, all-electric whole-building heat pumps make up half of space heating sales by 2030 and roughly three-fourths of installed space heating equipment in 2050. In addition, dual-fuel heat pumps account for 40 percent of space heating sales in 2030, and 16 percent of installed space heating equipment in 2050. Early replacements—retiring equipment before its end of useful life—are necessary in the Full Electrification case to achieve 100 percent emissions reductions by 2050; approximately 6 percent of households and 3 percent of commercial floor area will need to install heat pumps in place of existing heating systems before the end of those systems' useful lives.

[40] California Air Resources Board. "Temporary Pathways Table (Table 8)." Available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[41] Note that these emissions factors do not include methane emissions associated with pipeline leaks.

Table 5. Market share, stock, and electricity consumption results for modeled scenarios

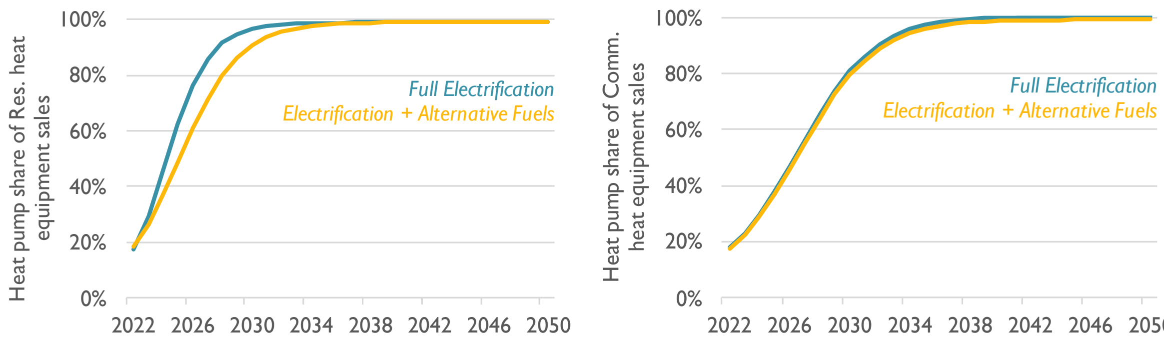
Metric	Full Electrification	Electrification + Alternative Fuels
All-electric heat pump share of residential space heat equipment sales in 2030	97% (approx. 110,000 per year)	50% (approx. 56,000 per year)
Heat pump share of installed residential heating systems in 2050 by type	All-electric ASHP: 91% Dual-fuel ASHP: 0% GSHP: 5%	All-electric ASHP: 71% Dual-fuel ASHP: 16% GSHP: 3%
Cumulative residential space heat pump early replacements	161,500	0
All-electric heat pump + GSHP share of commercial space heat equipment sales in 2030	80%	43%
Heat pump share of installed commercial heating systems in 2050 by type	All-electric ASHP: 93% Dual-fuel ASHP: 0% GSHP: 4%	All-electric ASHP: 75% Dual-fuel ASHP: 18% GSHP: 2%
Cumulative amount of commercial floor area converted through heat pump early replacements	91 million square feet	0
Percent of homes in 2050 connected to gas infrastructure	0.2%	21%
Percent of commercial building square footage in 2050 connected to gas infrastructure	0.1%	19%
Residential and commercial electricity consumption from thermal loads across all end-uses in 2050	25.4 TWh	23.1 TWh

2.4.1 Heat Pump Market Shares

As shown in the figures below, to reach net-zero emissions by 2050, heat pump sales must dramatically increase by 2030 in both the commercial and residential sectors compared to current market trends.

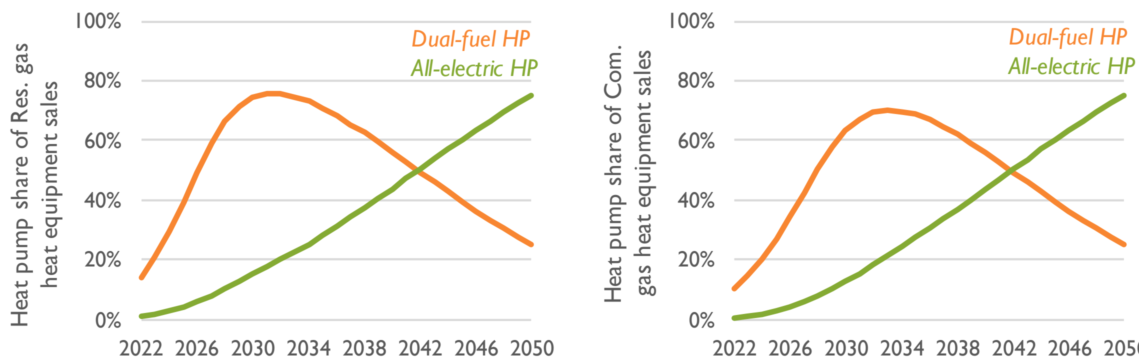
Both scenarios assume aggressive electrification trajectories in order to meet the 2050 net-zero emissions target. However, the two scenarios differ greatly on the breakdown of the sales of heat pumps intended to serve a whole-building load versus smaller heat pumps that would be integrated with existing or new gas heating as a backup ("dual-fuel heat pump"). As shown in Figure 4, in the residential sector, the Electrification + Alternative Fuels case lags slightly in terms of total heat pump adoption (combined sales of all-electric and dual-fuel heat pumps). In the commercial sector, we assumed the same heat pump adoption trajectory for both scenario., In the Electrification + Alternative Fuels case, the total heat pump sales are split between dual-fuel and all-electric whole-building heat pumps replacing gas equipment, as shown in Figure 5.

Figure 4. Total heat pump market shares by scenario



Total combined heat pump sales (all-electric and dual-fuel) in the residential (left) and commercial (right) sectors as a percentage of total space heat equipment sales.

Figure 5. Dual-fuel heat pump and all-electric heat pump share of gas equipment replacements sales in the Electrification + Alternative Fuels scenario



Dual-fuel heat pump and all-electric whole-building heat pump sales in the residential (left) and commercial (right) sectors as a percentage of space heat equipment sales replacing gas equipment in the Electrification + Alternative Fuels scenario.

2.4.2 Emissions

Under the Full Electrification scenario, emissions from residential and commercial buildings reach zero in 2050 through aggressive electrification trajectories, as shown in Figure 6. In the Electrification + Alternative Fuels case, there are still some emissions from the building sector in 2050 from the use of RNG for residential and commercial buildings.[42]

[42] Cost-effectively achieving a net-zero target for the buildings sector before 2050 would require the use of offsets from carbon removal or emission reductions in other sectors or locations, not modeled in this analysis.

Figure 6. Emissions by fuel type for the Full Electrification scenario (left) and Electrification + Alternative Fuels scenario (right)

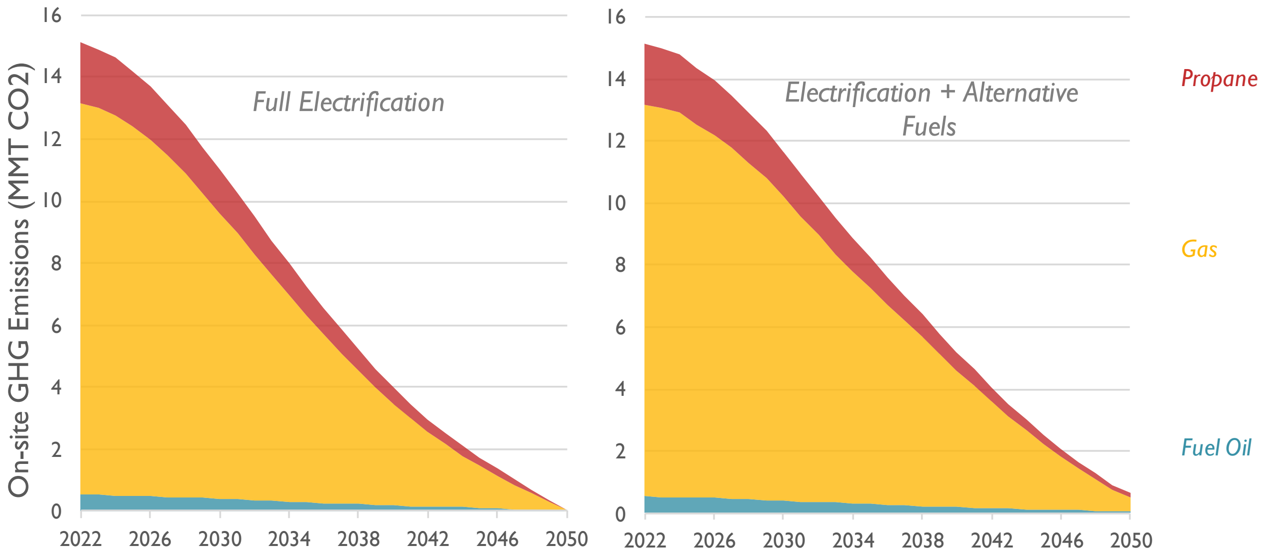


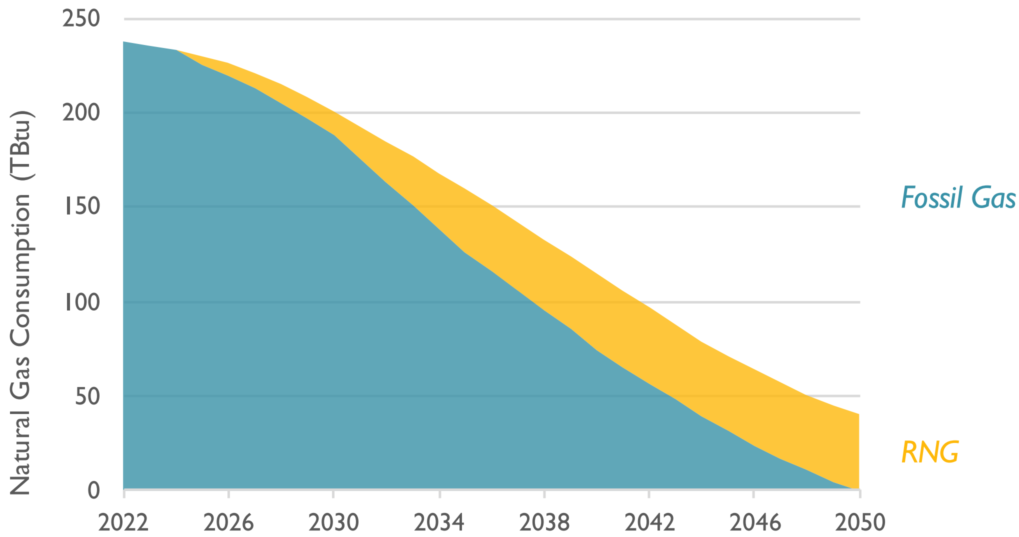
Table 6 shows the emissions in each scenario in 2030 and 2050, compared to 2021 levels. In 2030, emissions reductions relative to 2021 levels are roughly similar, with slightly higher emissions in the Electrification + Alternative Fuels scenario. Cumulative emissions in the Electrification + Alternative Fuels scenario are 9 percent higher than the Full Electrification scenario, due to the continued use of gas appliances using RNG.

Table 6. Emissions by scenario for key years

Scenario	2021 *MMT CO2e*	2030 *MMT CO2e*	2050 *MMT CO2e*	Cumulative (2021-2050) *MMT CO2e*
Full Electrification	15.3	11.0	0	222.2
Electrification + Alternative Fuels	15.3	11.7	0.6	243.0

Figure 7 shows the total utility gas consumption in the Electrification + Alternative Fuels scenario by type of fuel (fossil gas and RNG). RNG is slowly integrated into the gas system starting in 2025, and by 2050 RNG serves all natural gas consumption in residential and commercial buildings.

Figure 7. Natural gas consumption breakdown, Electrification + Alternative Fuels scenario



2.4.3 Appliance Stock

Figure 8 and Figure 9 show the trajectories of space heating stock for residential and commercial buildings in the Full Electrification scenario. In this scenario, all-electric whole-building ASHPs are the primary decarbonization strategy for buildings.[43] This scenario assumes that in the last five years leading up to 2050, some fossil fuel equipment will be replaced with heat pumps before the end of its useful life in order to meet the 2050 net-zero targets. These "early replacement" heat pumps are shown in light blue in the figures below. By 2050, 91 percent of residential households have an ASHP, and 5 percent have a GSHP.

[43] We included existing district heating systems in this analysis; however, we did not model any new district heating or network geothermal systems as part of the building analysis. For more discussion on network geothermal, see Section 7.3.

Figure 8. Residential space heating stock, Full Electrification scenario

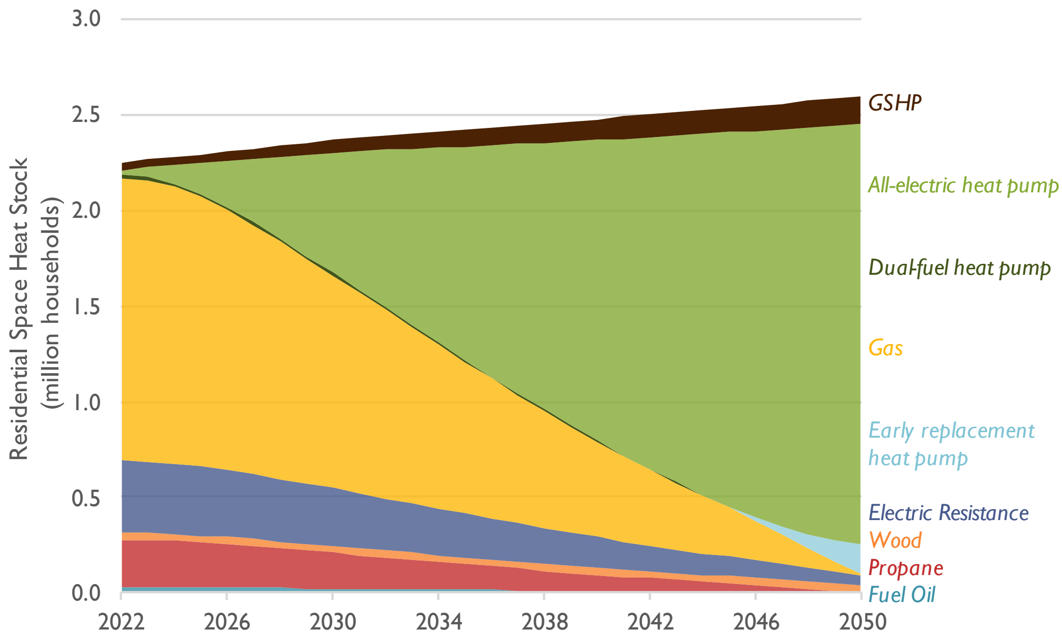


Figure 9. Commercial space heating stock, Full Electrification scenario

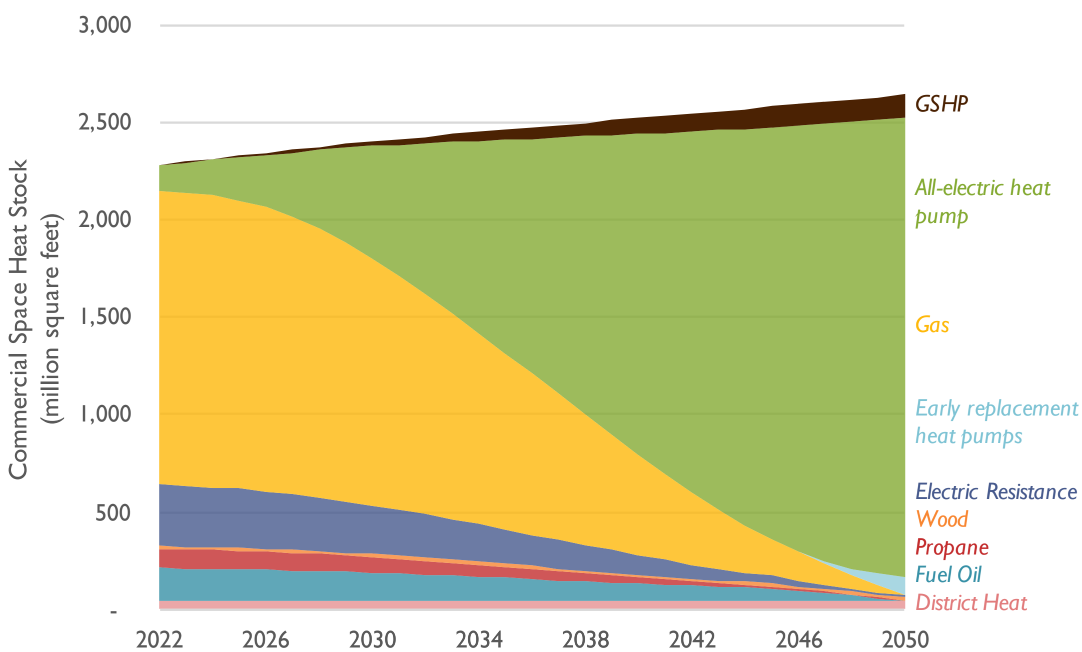


Figure 10 and Figure 11 show the residential and commercial stock breakdowns under the Electrification + Alternative Fuels case. The major difference is the large number of households and commercial buildings that will rely on dual-fuel heating systems by 2050, retaining their connections to gas infrastructure.

Figure 10. Residential space heating stock, Electrification + Alternative Fuels scenario

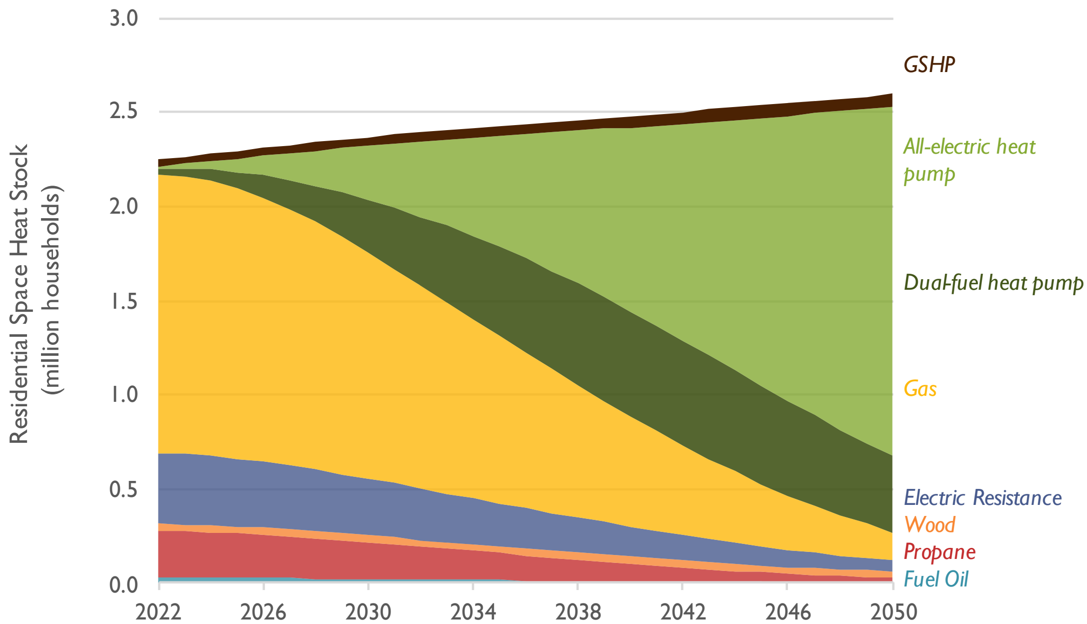
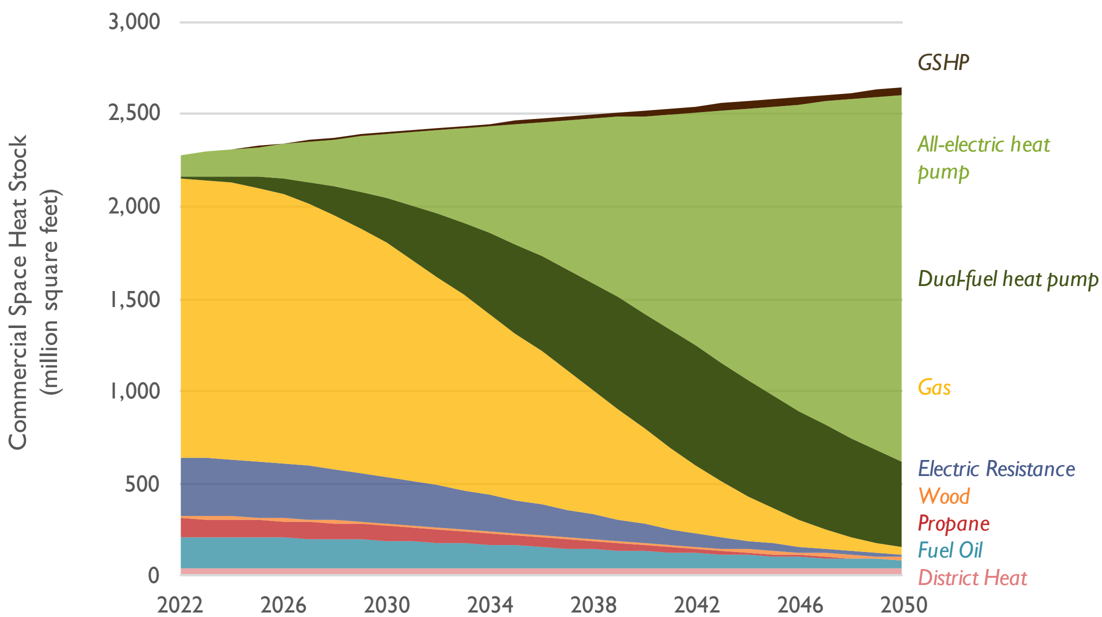


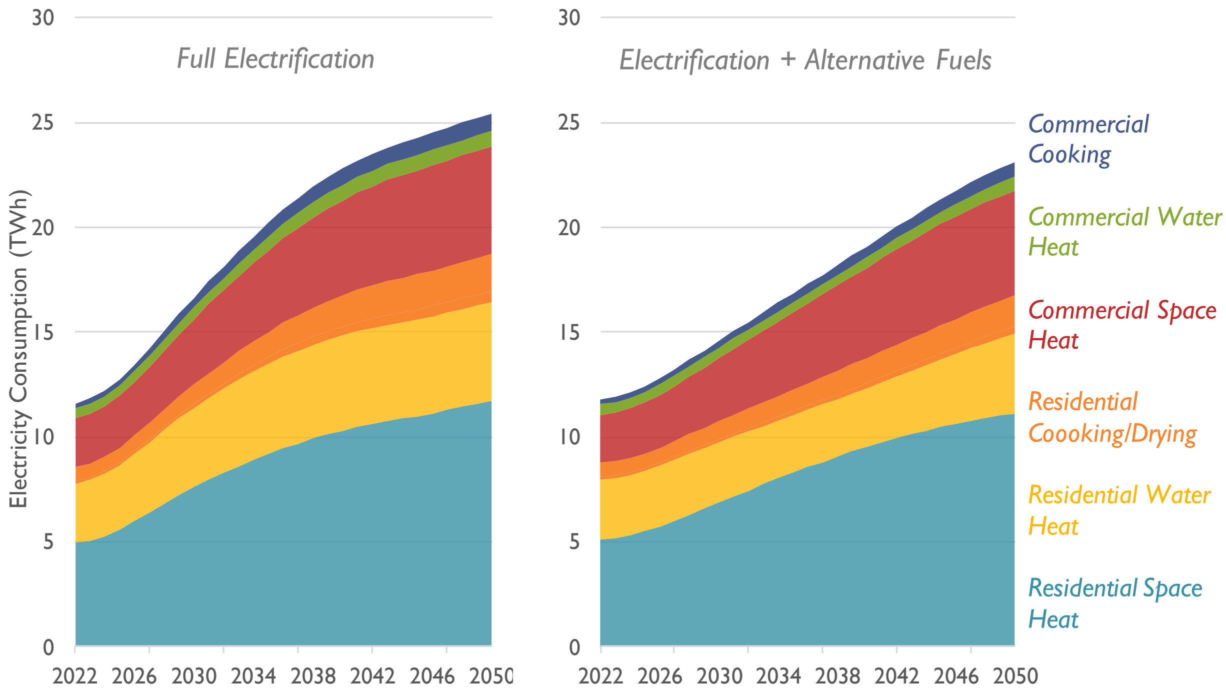
Figure 11. Commercial space heating stock, Electrification + Alternative Fuels scenario



2.4.4 Electricity Consumption

Figure 12 shows the projected annual electricity consumption of the residential and commercial sectors for both scenarios. The Full Electrification case and the Electrification + Alternative Fuels case are projected to roughly double annual electricity consumption. The Full Electrification case is projected to require roughly 10 percent more electricity in 2050 than the Electrification + Alternative Fuels case. Space heat drives the majority of electricity consumption in both sectors, followed by water heat. In the Full Electrification case, more homes switch from gas to electric water heaters, whereas we assumed homes that retain gas for space heating in the Electrification + Alternative Fuels case continue to keep their gas water heating equipment.

Figure 12. Annual electricity consumption by sector and end-use for Full Electrification and Electrification + Alternative Fuels scenarios



3. Gas System Impact Analysis

Based on the results of the building decarbonization analysis, Synapse analyzed the customer and utility financial impacts of the Full Electrification and Electrification + Alternative Fuels scenarios. For this analysis, we focused on the three largest gas utilities in Minnesota: Northern States Power Company (Xcel), Minnesota Energy Resources Corporation (MERC), and CenterPoint Energy Resources Corporation (CPE). For our purposes, we modeled these three utilities as one combined master utility in Minnesota.

3.1 Methodology and Key Assumptions

3.1.1 Gas Rate Model Overview

For this analysis, we used Synapse's in-house Gas Rate Model (GRM) to model and analyze the utilities' finances and customer impacts for the two scenarios. The GRM allows Synapse to project gas or electric utility rates based on different scenarios for utility investment, sales, and financial models. We use input data from annual utility reports to state regulators, alongside materials submitted to the Pipeline and Hazardous Materials Safety Administration (for gas pipeline investment data) and rate cases, as needed, to build a model of the past up to the present. The model tracks utility plant in service, depreciation, capital additions and retirements, operations and maintenance, and income taxes. It also accounts for capital structure and changes in tax rates.

Looking to the future, the model allows us to test scenarios for different levels of investment and customer growth or decline, pipeline replacement programs, early retirements, stranded costs, and changes in depreciation rates. These cases can correspond to electrification or other decarbonization scenarios developed in the BDC tool described above in Section 2.2.1. We have developed methods to map changes in customer numbers to changes in miles of pipeline in service and other aspects of capital plant.

The model distinguishes between commercial and industrial customers to better capture the impact of large building electrification, alongside continued reliance on natural gas (either fossil or alternative fuels) in the industrial sector. The focus of our analysis in this report is the building sector, so we present here the results for residential and commercial sectors. The industrial sector projection is necessary to account for the allocation of large-pipe system costs as that sector begins to be the dominant remaining sector using the natural gas network. In the absence of a pathway analysis for decarbonization of Minnesota's industrial sector, we apply a forecast of industrial customer sales based on scaling the state of Washington's State Energy Strategy.[44] This pathways model projects a gradual decline in industrial gas use, on an energy basis, to about half of today's level by 2050.

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[44] Washington State Department of Commerce. 2020.*Washington State Energy Strategy Appendix B: Data Accompanying Deep Modeling Technical Report*. Available at https://www.commerce.wa.gov/wp-content/uploads/2020/12/Appendix-B.-Data-Accompanying-WA-SES-EER-DDP-Modeling-Report-12-11-2020.xlsx.

3.1.2 Scenario Descriptions

Synapse analyzed two scenarios in the GRM, based on the two BDC scenarios: Full Electrification and Electrification + Alternative Fuels. We assumed that each potential future was pursued intentionally, and therefore, the Minnesota utilities incorporated the expected futures into their capital structure, investment plans, and cost recovery.

We note that these scenarios do not account for the potential for gas utilities to engage in new business models or new lines of business (such as heating equipment provision or networked geothermal systems); we evaluate only the traditional gas-delivery portion of their business. By anticipating changes in gas delivery demand and planning for the transition, we assume that the utilities are able to recover all invested capital, with a fair rate of return, as they transition to a decarbonized future.

3.1.2.1 Full Electrification Scenario

The Full Electrification scenario assumes that most customers electrify and depart the gas system by 2050. Accordingly, by 2050, 91 percent of residential and commercial customers have departed the gas system (as compared to 2022). At the same time, fossil gas sales to the buildings sector have decreased by more than 99 percent. Industrial customers become the dominant set of gas utility customers in this case.

To reflect the utilities' planning for the strategic decommissioning of the portions of the gas system that serve the buildings sector, alongside full electrification, we assumed that the utilities would pursue clustered electrification and would update their depreciation rates.

First, we assumed that customer departures from the gas system would be largely clustered. By doing so, the utilities would be able to retire sections of the gas pipeline as buildings electrify. This allows the total system costs to decrease (as fewer miles of pipeline need to be maintained), minimizing the increase in costs for customers remaining on the system.

To capture clustered electrification, we assumed that, by 2031, 80 percent of electrification took place in clustered neighborhoods, and the corresponding portions of the pipeline system could be retired. Similarly, we assumed that, by 2034, over 80 percent of services that have reached the end of their useful life will be retired rather than replaced, and the associated buildings will be electrified. In addition to removing retired assets from rate base, a smaller system results in lower operations and maintenance costs.

Secondly, we assumed the utilities would update their depreciation approach to better recover costs before customers depart the gas system. For the Full Electrification scenario, we assumed that the utilities depreciated out all of their assets by 2050 by applying a 5.1 percent depreciation rate to all assets (unless the asset's historical rate was higher, in which case the higher rate was used). This is roughly double current typical distribution asset depreciation rates. The net effect of this accelerated depreciation is to bring the utility's rate base to zero in 2050.

3.1.2.2 *Electrification + Alternative Fuels Scenario*

For the Electrification + Alternative Fuels scenario, we assumed that, by 2050, gas sales to the buildings sector will decrease by 86 percent (as compared to 2022), and 63 percent of residential and commercial customers will depart the gas system. Thus, while the number of customers does not decrease as much as compared to the Full Electrification case, gas sales still significantly decrease below 2022 values. Most remaining utility customers are in residential and commercial buildings, but most energy is delivered to industrial customers.

We also assumed that the utilities pursue some clustered electrification, but given that more customers remain on the system by 2050, the clustered electrification is not as aggressive as in the Full Electrification scenario. We assumed there would be some clustering and planned infrastructure retirement because the overall system cost would be more reasonable than a case in which the full system is maintained to serve only 37 percent as many customers. Accordingly, by 2029, half of all customers who depart the gas system do so as part of a clustered/neighborhood departure, and the other half are scattered across the gas system. This ratio holds constant through 2041. In 2037, the fraction of electrification that is clustered begins to ramp up by 1 percent per year. This assumption of increasing clustering reflects a scenario in which sufficient numbers of customers have departed in some areas where it is more likely that any given house leaving the system allows a segment to be retired. Similarly, by 2039, 25 percent of gas service lines that reach the end of their useful life are retired instead of replaced, and the corresponding homes are electrified. Because there are fewer departures, and less clustering of those who do depart, operations and maintenance costs do not fall as much in this case as in the Full Electrification case.

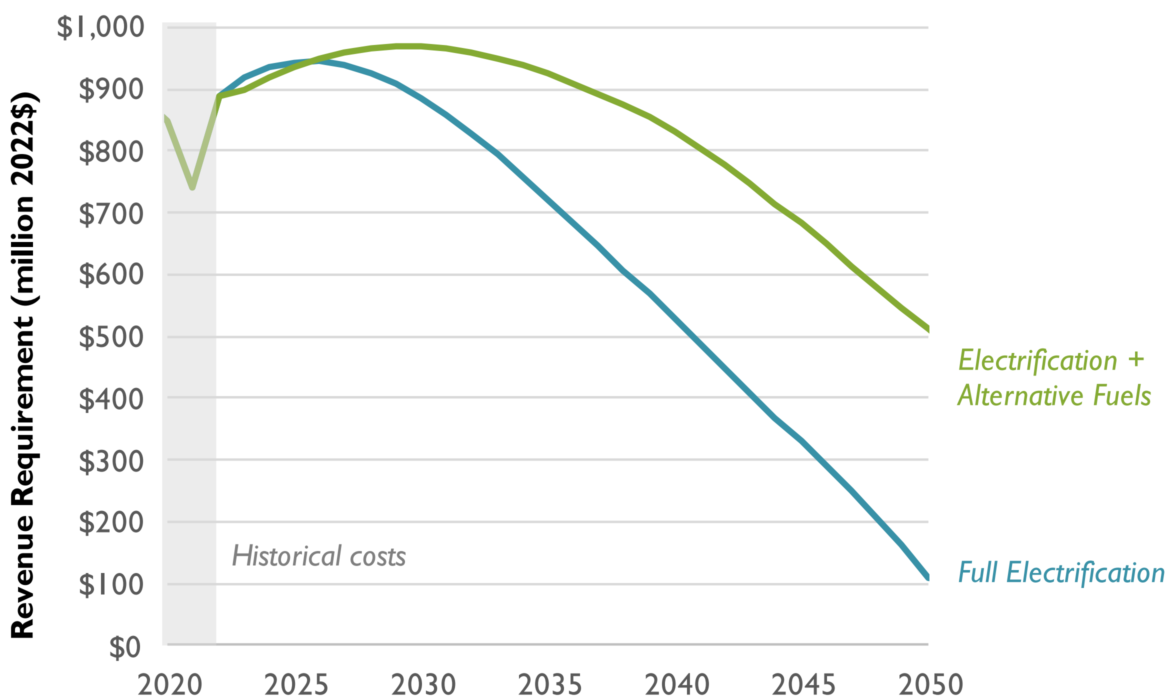
The Electrification + Alternative Fuels scenario assumes that depreciation is accelerated in order to recover more costs before significant numbers of customers leave the gas system and gas sales volumes fall further. Unlike the Full Electrification scenario, which assumes zero rate base by 2050, the Electrification + Alternative Fuels scenario assumes that some assets are not fully depreciated in 2050. The scenario does not require as aggressive depreciation rates because more customers remain on the system in 2050 and beyond and, thereby, are available to continue paying for the gas system's costs. As such, the scenario assumes the higher of a 4.6 percent depreciation rate or the asset's historical depreciation rate. By 2050, rate base is 15 percent of the 2022 rate base value under this depreciation methodology, corresponding to 14 percent remaining gas sales volume relative to today.

Finally, in the Electrification + Alternative Fuels scenario, we assumed that RNG makes up an increasing portion of the gas throughput in the system, reaching 100 percent in 2050.

3.2 Results

We analyzed a series of gas utility financial and customer impact results for the Full Electrification and Electrification + Alternative Fuels scenarios. We found that the residential and commercial revenue requirement for the gas utilities by 2050 would be significantly lower under the Full Electrification scenario than under the Electrification + Alternative Fuels scenario. This is due to the accelerated depreciation under the Full Electrification scenario, as compared to the Electrification + Alternative Fuels scenario (Figure 13). In the Full Electrification scenario, the gas utility is focused entirely on serving industrial sector customers in 2050 and beyond. Additionally, the revenue requirement in the Full Electrification scenario has the potential to be decreased somewhat further through adjustments to the utilities' capital structures.[45] The largest driver of the difference between the revenue requirements in the two cases is operations and maintenance costs: serving more customers over more miles of pipe requires more revenue. The Electrification + Alternative Fuels case also has greater depreciation costs than the Full Electrification case because more capital additions are made to the larger remaining system to keep it safe and reliable. These additions are then depreciated quickly so that rate base can scale down with sales to manage rate pressure from return on rate base and mitigate stranded cost risk.

Figure 13. Residential and commercial gas revenue requirement



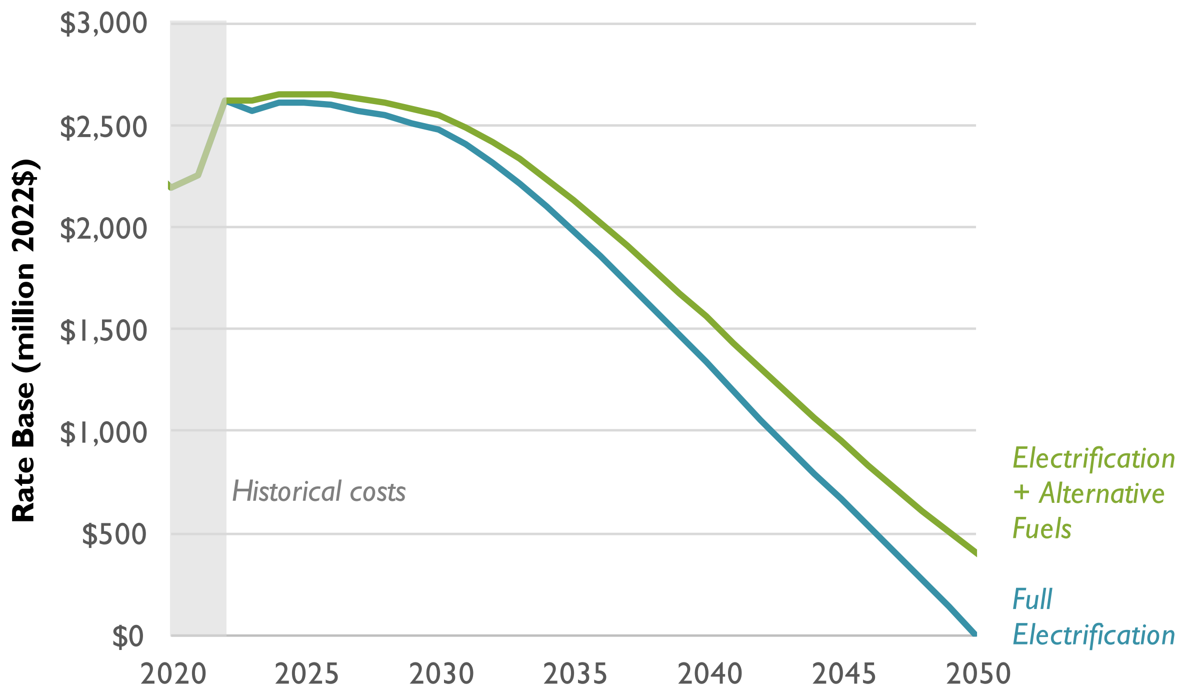
The Minnesota gas utility rate base has risen substantially in the last few years. In both scenarios, residential and commercial rate base growth goes almost flat in the first few years of the study period, as increased depreciation balances with capital additions (Figure 14). As the analysis period goes on, rate base begins to decrease more quickly.[46] This is a result of the accelerated depreciation approach, as well as increased customer departures due to electrification, and the associated retirement of their

[45] When depreciation rates increase, utility cash flow relative to debt increases. This means that the equity share of company capital can be decreased while maintaining the same credit rating; a lower weighted average cost of capital would thereby be used when setting rates. We expect the net effect on revenue requirement of making this adjustment would be less than 5 percent.

[46] Rate base decline begins to accelerate in the later years, reflecting the modeling assumption that electrification and pipelines retired instead of replaced increases over time.

services and meters. Accelerated depreciation allows for the recovery of the cost of the assets faster, leaving a smaller rate base by 2050. With more customer departures, the utilities do not continue to make as many capital investments in the system, and, due to clustered electrification, they retire portions of the system.

Figure 14. Residential and commercial rate base



In both scenarios, customers who remain on the gas system are also expected to face higher rates and have higher annual gas bills, even with decreased fuel use per customer in the Electrification + Alternative Fuels scenario. To estimate these impacts, we divided the residential portion of the utilities' revenue requirement and associated fuel costs by the number of dekatherms used by residential customers per year and, separately, by the number of residential customers per year. The same analysis was performed for commercial customers.

In the Full Electrification scenario, residential and commercial rate increases are mitigated by accelerated depreciation and clustered electrification. By the early 2040s, rates in the Full Electrification scenario have doubled, while rates in the Electrification + Alternative Fuels scenario have tripled, driven by the high costs of alternative fuels and rising delivery rates. By the late 2040s, as most customers have departed the gas system, rates begin to spike because the costs of the delivery system must be split over fewer and fewer dekatherms of gas delivered (Figure 15 and Figure 16). Policies should be put in place to assist customers remaining on the gas system. This policy assistance will be critical, as those remaining are likely to be those with the least ability to choose to electrify and depart the gas system, such as low- and moderate-income customers and renters. Electrification programs could also target electrification to vulnerable customers, so they are not the last users of the gas system. In the

Electrification + Alternative Fuels case, dual-fuel heating customers would dominate the utilities' customer base, paying high rates per dekatherm but consuming relatively few dekatherms.

Figure 15. Residential gas revenue per dekatherm

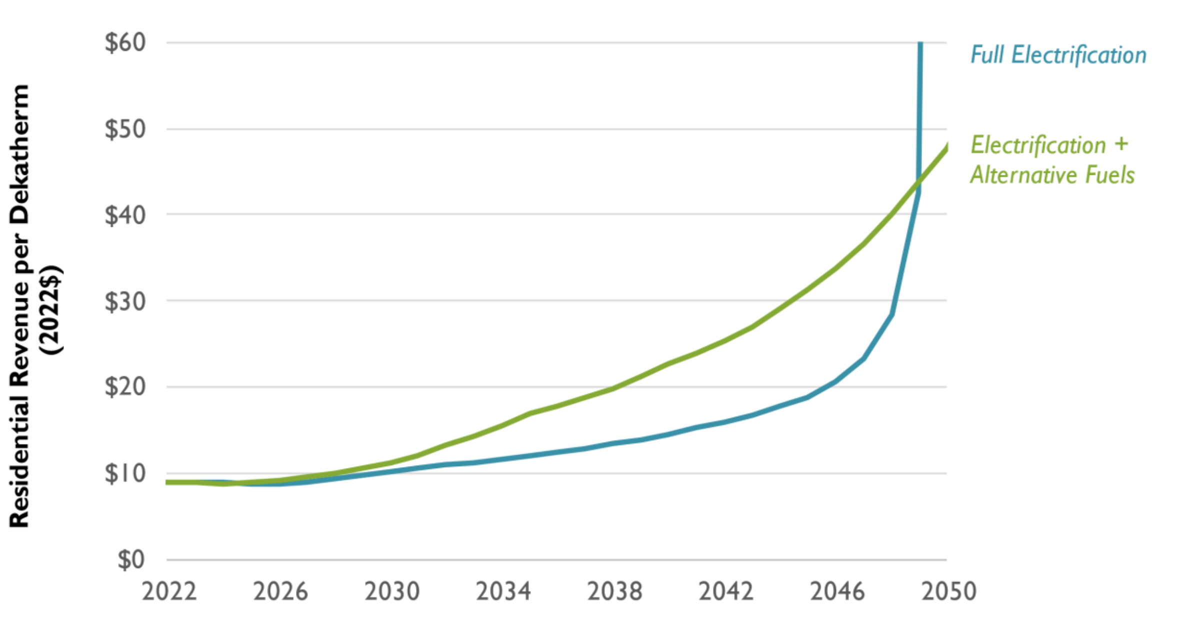
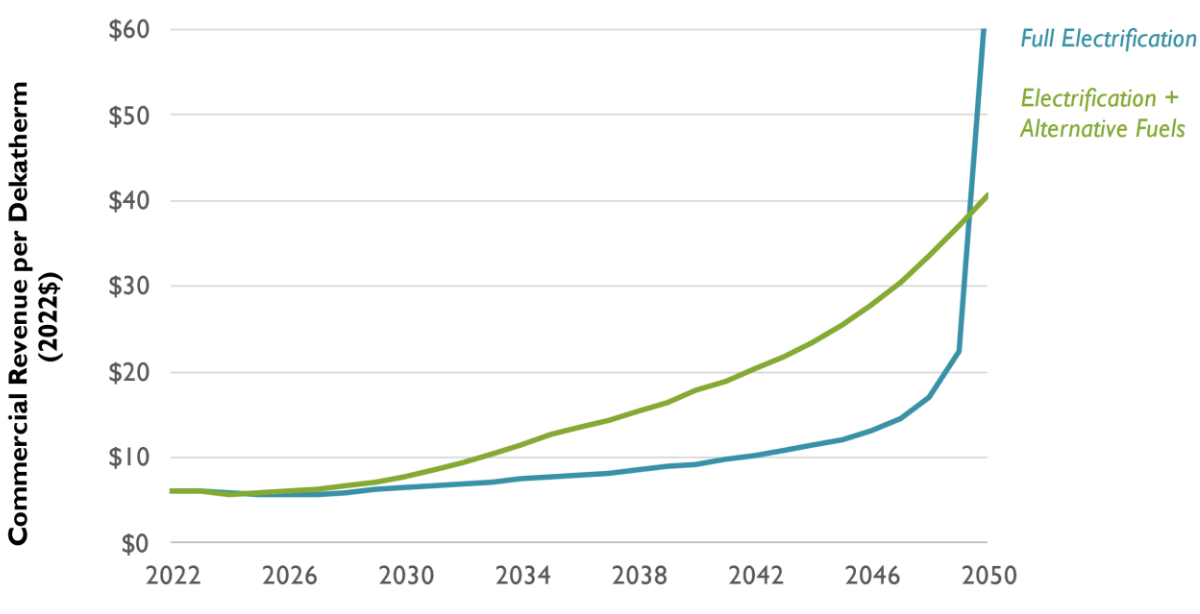
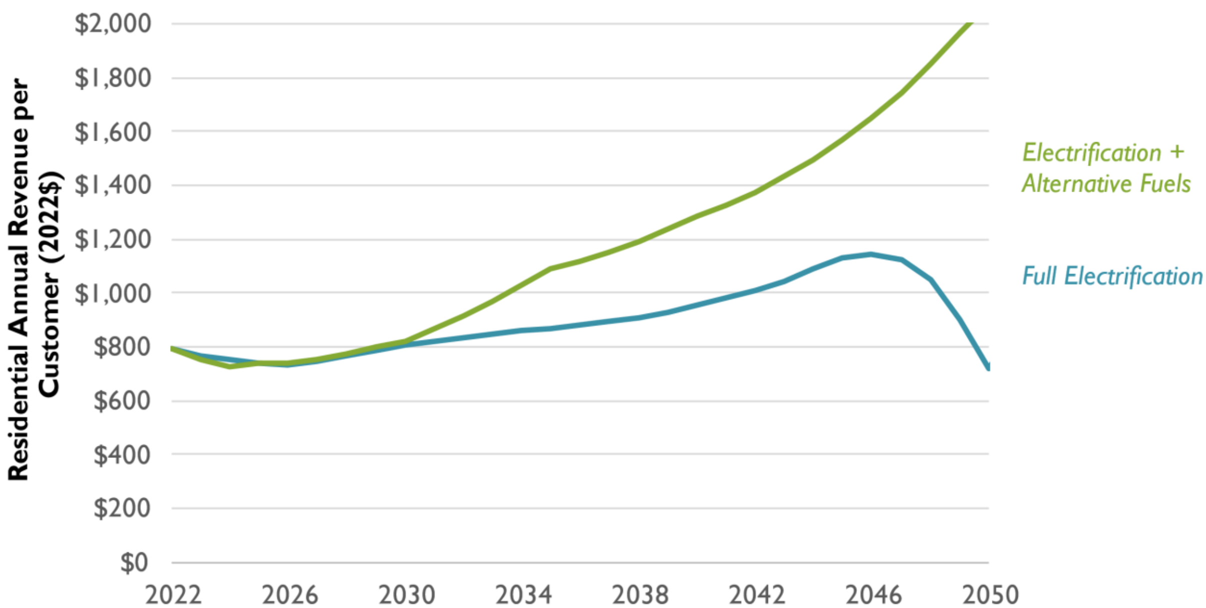


Figure 16. Commercial gas revenue per dekatherm



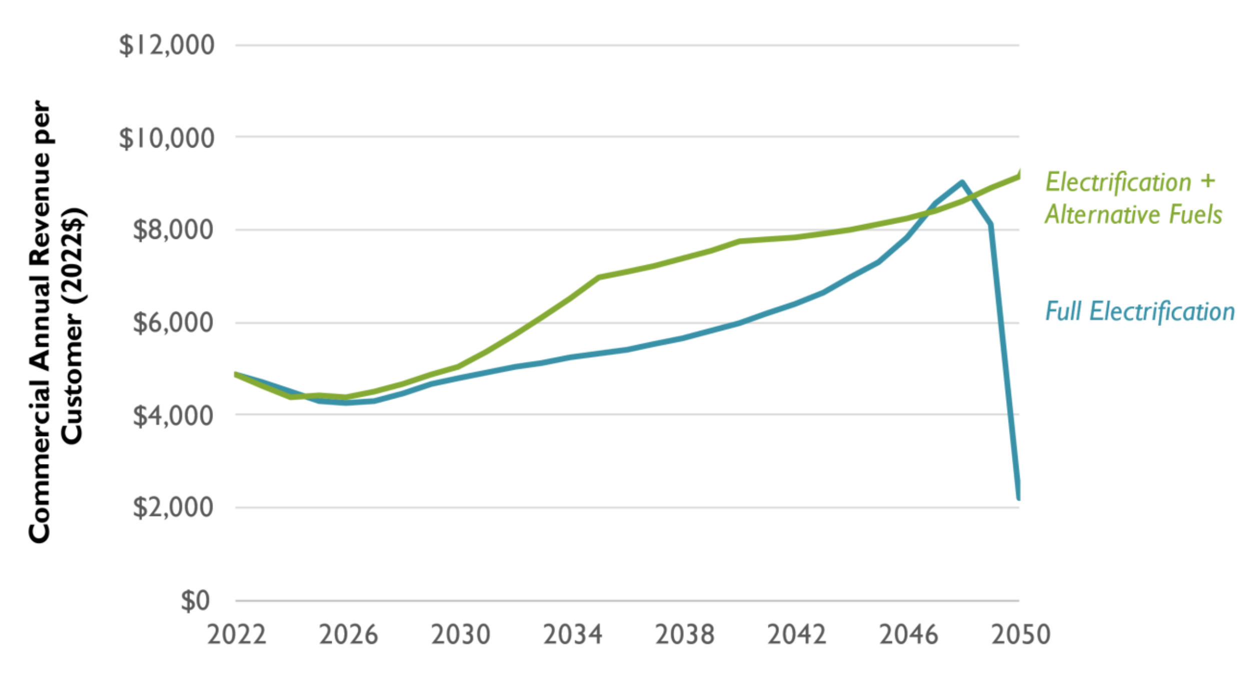
For residential customers, annual gas bills are expected to increase under both scenarios by 2050 (Figure 17). Annual residential bills under the Electrification + Alternative Fuels scenario are over twice as high in 2050 than in 2022. However, under the Full Electrification scenario, annual bills stay lower for longer, allowing more time for the smooth transition from gas to electric home heating. As fewer customers remain on the gas system to pay for the costs of maintaining the system, those who remain face increasing bills. We see a sharp decline in bills in the Full Electrification case in the final years before 2050, as residential per-customer consumption falls faster than rates increase. The increasing allocation of remaining gas system costs to the industrial sector helps to mitigate rate increases for the residential and commercial sectors. While more customers remain in the Electrification + Alternative Fuels case than in the Full Electrification case, the higher cost of fuels in this case results in higher overall bills

Figure 17. Annual residential customer costs



For commercial customers, annual bills in the mid-2040s in the two scenarios are roughly 50 percent higher than in 2022 (Figure 18). As with residential bills, commercial bills remain lower for longer under the Full Electrification scenario, compared to the Electrification + Alternative Fuels scenario, and then see a sharp decrease leading up to 2050 due to the industrial cost allocation. The somewhat different dynamics of the commercial and residential sectors occur as a result of different usage per customer and how delivery costs are allocated between the sectors. In the event that the sectors electrify at different paces than those modeled here, or if the industrial pathway is different than we have assumed, the dynamics of splitting cost recovery between the sectors would be different, particularly in the later years.

Figure 18. Annual commercial customer costs



Overall, the results point to the importance of intentional utility planning to ensure customer costs do not increase uncontrollably and to minimize the risk to the utilities, their shareholders, and ratepayers.

In the Full Electrification scenario, customer costs for those remaining on the gas system can be mitigated by incorporating clustered electrification and accelerated depreciation. This advance planning is critical for protecting customers, particularly for protecting those who will face the most difficulties electrifying their homes (such as low- and moderate-income households and renters).

Under the Electrification + Alternative Fuels scenario, accelerated depreciation and clustered electrification also help mitigate customer cost increases, although fuel costs result in higher overall bills. This scenario faces increased risks associated with uncertain availability of RNG, uncertain RNG costs, and uncertainty around RNG's ability to effectively reduce greenhouse gas emissions.

4. Electric System Impact Analysis

Most of Minnesota's electricity service area is located within the Midwestern Intercontinental System Operator's (MISO) Local Resource Zone (LRZ) 1. In 2022, LRZ-1 peaked on June 20 at 6:00 pm, at a peak load of 17,405 MW.[47] In 2021, Minnesota electric customers consumed 66.6 TWh with a roughly even

[47] MISO Market Reports. "2022 Historical Daily Forecast and Actual Load by Local Resource Zone (xls)," December 31, 2022. Available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Daily%20Forecast%

split between the residential, commercial, and industrial sectors.[48] As building decarbonization is pursued, and heating is increasingly provided by electricity rather than other fuels, it is important to estimate the effect on the system's peak load. Our analysis suggests it is highly likely that Minnesota's electric grid will transition to winter-peaking within the next decade or so due to building electrification, and grid planners must begin considering these impacts soon. This section presents the methods and results of our electric system impact analysis.

4.1 Methodology and Key Assumptions

4.1.1 Overall approach

We analyzed and projected electric peak-load impacts due to building electrification through 2050 for the two scenarios we analyzed in the previous section. While our analysis focuses on the impacts of electrification measures for space heating, water heating, cooking, and clothes drying in the building sector, it includes a projection of peak loads for the entire residential, commercial, and industrial sector so that we can show the relative impacts of building electrification on the overall electricity system. Our analysis does not include any impact of electric vehicle (EV) loads. However, it is important to note that winter peak hours occur in the early morning (e.g., 7 am) and that many EVs are expected to be fully charged by early morning. This means that EV peak load impacts are expected to be substantially lower during the winter than the impacts during the summer. For the industrial sector, as well as other end uses (e.g., lighting, refrigeration, ventilation) for the residential and commercial sectors, we assume a moderate level of load growth through 2050 commensurate with AEO 2023 for the Midcontinent West region.[49]

We estimated hourly loads at the end-use level primarily based on NREL's *End-Use Load Profiles for the U.S. Building Stock* (NREL EULP) database consisting of calibrated outputs from NREL's ResStock and ComStock models.[50,51] We aggregated all the residential and commercial building load data for Minnesota available in NREL's end-use load database. We then developed hourly load scaling factors (representing hourly load fractions relative to the total annual loads) for several key end uses including

20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

48 U.S. EIA. 2021 Form EIA-861. Available at: https://www.eia.gov/electricity/data/eia861/ (Note: At the time of analysis, 2022 data was still preliminary).

49 The analysis assumes residential minor end-use load growth of 0.6 percent per year, and commercial minor end-use and industrial load growth of 0.3 percent per year per AEO 2023.

50 National Renewable Energy Laboratory (NREL). n.d. *End-Use load Profiles for the U.S. Building Stock.* Distributed by NREL. Available at: https://www.nrel.gov/buildings/end-use-load-profiles.html.

51 The NREL database is the most comprehensive end-use load profile database that provides sub-hourly load profiles for the residential and commercial building sectors across a variety of end-use appliances for 48 states and the District of Columbia. ResStock and ComStock are physics-based simulation models that draw upon many granular data sources to derive a truly representative building stock input. Outputs from the models were then calibrated against measured load from a variety of empirical data sources. For details of ResStock and ComStock modeling, see U.S. Department of Energy. Office of Energy.

space heating, water heating, cooking, and clothes drying, as well as for the rest of the end uses in the building sector. This analysis relied exclusively on NREL EULP for the major end uses except for heat pumps for space heating (including both ASHPs and GSHPs), for which we relied on NREL EULP as well as other data sources. The NREL EULP database we used for this analysis contains granular load data by end use based on the actual 2018 weather data across the state. For the purpose of our space heating load analysis (which will be discussed in detail later in this section), we weighted county-specific hourly weather data (used for NREL EULP database) by the amount of total gas heating demand across all counties and developed consumption-weighted hourly temperature data for the entire state. The lowest, weighted average temperature across the state in this data set is approximately -15°F, which occurred in January 2018. For the industrial sector load shapes, we applied the 2022 MISO Zone 1 load profile.

We estimated hourly load scaling factors by estimating the load for each hour as a percentage of the total annual load for a given end use. We then applied the end-use-specific hourly load factors to our estimates of annual electric loads by end use and estimated hourly loads for the current year, 2030, 2040, and 2050. It is important to note that our main analysis discussed in this section does not account for any peak-load mitigating measures. Utilities and consumers can implement various load mitigation measures such as active load management of space heating through smart thermostats and direct load control of HPWHs, targeted energy efficiency, and demand response measures for commercial buildings (e.g., lighting, ventilation). This means our analysis presents a conservative picture of the expected impacts due to building decarbonization. That is, the state's electric utilities should be able to reduce winter peak loads expected from electrification more than our scenario analysis presents if they employ peak-load mitigation measures. However, we conducted a high-level assessment of demand response potential estimates for space and water heating end uses as a sensitivity analysis (described in Section 7.2).

As mentioned above, we employed a different methodology to estimate hourly load impacts from heat pumps (ASHPs and GHSPs). This is because heat pumps are expected and projected to be the major building decarbonization technology among all technologies and also because the performance of heat pumps, in particular ASHPs, is significantly affected by outdoor temperature, as we discussed in detail in Chapter 2.3.3. Our overall approach is to start with NREL EULP's gas heating load shapes[52] and convert them into heat pump load shapes based on our own estimates of hourly heat pump efficiencies, expressed in COP, as well as the hourly temperature data mentioned above. For our analysis of ASHPs, we developed hourly COP curves based on a 2016 in-field evaluation study of heat pumps,[53] and then

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[52] Office of Efficiency & Renewable Energy. 2022. *End-Use Load Profiles for the U.S. Building Stock - Methodology and Results of Model Calibration, Validation, and Uncertainty Quantification*. Available at: https://www.nrel.gov/docs/fy22osti/80889.pdf.

[53] Cadmus. 2016. *Ductless Mini-Split Heat Pump Impact Evaluation*. Prepared for the Electric and Gas Program Administrators of Massachusetts and Rhode Island Part of the Residential Evaluation Program Area. Available at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4755-TRM-DMSHP-Evaluation-Report-12-30-2016.pdf.

adjusted for the differences in performance by the type of heat pumps (i.e., ducted vs. non-ducted)[54] and the type of building (i.e., residential vs. commercial).[55]

Further, we adjusted the hourly heat pump load shapes to account for the impacts of (a) backup and supplemental heating used for ASHPs and (b) extreme weather events, which we discuss below.

Finally, we estimated the incremental transmission and distribution (T&D) investments needed to support building electrification by estimating net incremental peak loads that would be expected beyond a business-as-usual case.

4.1.1.1 Backup and supplemental heating

Minnesota is a cold-climate state and its minimum winter temperatures go well below 0°F. The capacity of heat pumps, especially ASHPs, to meet heating demand declines as the temperature drops even for cold-climate heat pumps. Thus, our analysis assumes backup and supplemental heating for ASHPs to meet heating demands during severely cold weather conditions. To determine the temperature point below which heat pumps require backup or supplemental heating, we rely on two heat pump evaluation studies conducted by the Center for Energy and Environment, which found such switchover temperature points could range from 10°F to -5°F in Minnesota, with the range affected by the type of heat pumps.[56] In contrast, GSHPs provide relatively stable heating outputs throughout the winter as GSHPs extract heat from the ground, which maintains stable temperatures. Thus, we assume that COP values for GSHPs would be the same through the winter season as the seasonal average value that was discussed in Chapter 2.3.3.2.

For dual-fuel ASHPs (those that rely on gas backup heating), we assume that heat pumps switch over to gas backup heating entirely when temperatures drop below 15°F. For all-electric whole-building heat pumps that rely on electric resistance (ER) supplemental heating (also called ER booster), we assume that heat pumps start operating along with an ER booster below 5°F and that the capacity of the heat pumps drop gradually to zero below -20°F. As the share of space heating provided by the ER boosters increases as the temperature drops to -20°F, we assume that the overall efficiencies of the combined

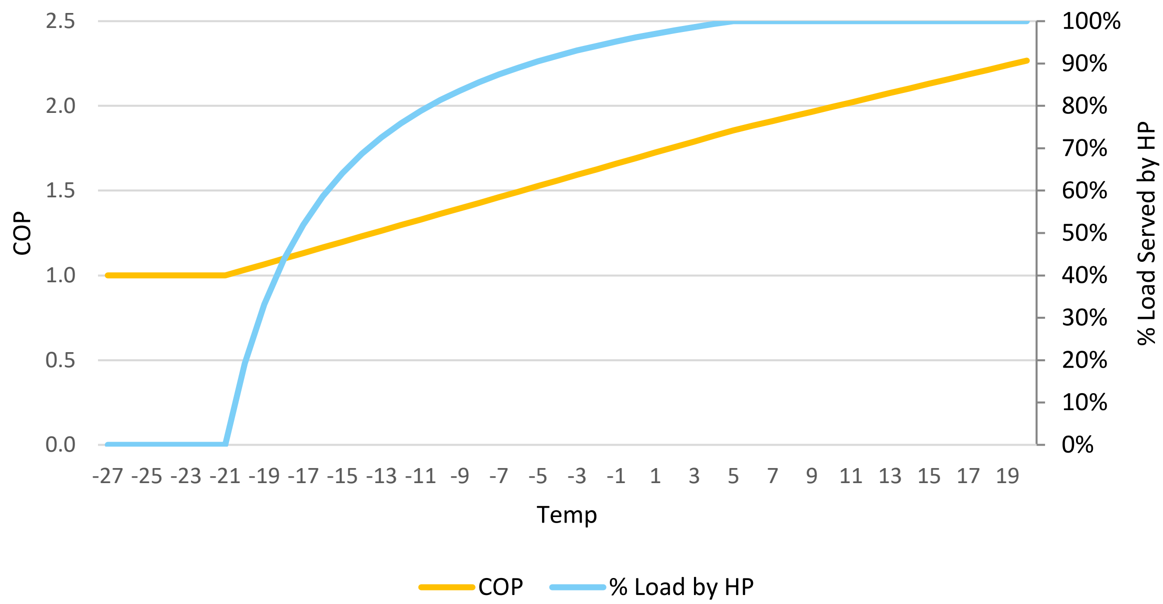
[54] We assume that the efficiencies of ducted heat pumps are approximately 12 percent less than the efficiencies of mini-split heat pumps based on a 2022 Cadmus study titled *Residential ASHP Building Electrification Study*. Available at: https://synapseenergyeconomics.app.box.com/file/1024523837562.

[55] We assume commercial systems are 20 percent more efficient than residential systems due to the availability of high temperature heat sources (including high COP values expected from VRF, a type of heat pump suitable for large commercial buildings, due to simultaneous heating and cooling functions).

[56] Center for Energy and Environment (CEE). 2018. *Field Assessment of Ducted and Ductless Cold Climate Air Source Heat Pumps*. Available at: https://www.mncee.org/field-assessment-ducted-and-ductless-cold-climate-air-source-heat-pumps; Center for Energy and Environment (CEE). 2022. *Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning*. Available at: https://www.mncee.org/investigation-air-source-heat-pumps-replacement-central-air-conditioning.

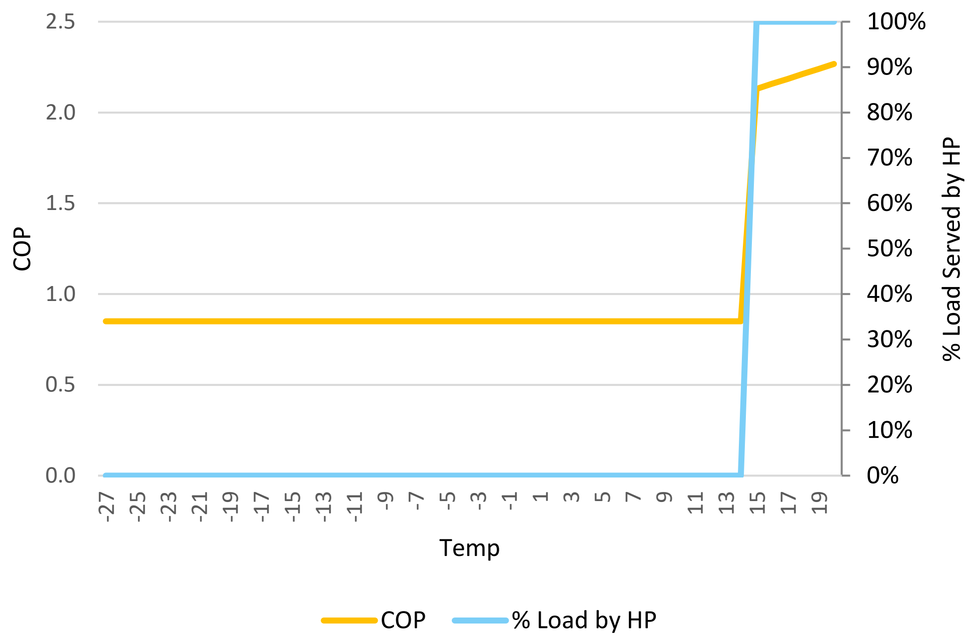
heat pump + ER systems decline linearly down to the efficiency of the ER boosters below -20°F.[57] This dynamic of heat pump efficiency and capacity values is presented in Figure 19 below for the range of temperatures from 20°F to -27°F. In contrast, dual-fuel heat pumps would serve full capacity down to 15°F (as discussed in Section 2.3.3), at which point the system's efficiency would drop to a COP of about 2.1 (as shown in Figure 20), and then switch entirely to an gas heating system below that temperature point. At that point the efficiency would drop to less than 100 percent (that is, equal to the efficiency of a gas heating system).

Figure 19. Whole building heat pump efficiencies (COP) and the share of space heating load served by a whole building heat pump



[57] As a reference, CEE's 2018 study found that a mini-split heat pump still supplied about 20 percent of the heating capacity that the system supplied at 5°F or higher.

Figure 20. Dual-fuel heat pump efficiencies (COP) and the share of space heating load served by a heat pump



4.1.1.2 Extreme weather events

Our analysis also considers the potential peak load impacts due to electrification during extreme weather events such as cold snaps by applying the industry practices used by HVAC contractors to size heating systems. This approach is different from that used by gas utilities to develop peak demand estimates for the gas system. We use this approach because space heating systems are entirely different technologies than gas pipelines and because HVAC contractors follow the HVAC industry practices instead of the gas companies' practices.

HVAC contractors typically size heating systems at winter design temperatures following the industry standard called Manual J that was developed by the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE).[58] A system sized to meet the load at the design temperature is expected to meet the full heating load during 99 percent of the hours of the year and part of the load for the remaining hours. HVAC contractors may then adjust the size upward slightly (relative to the heating load at a design temperature) following another standard called Manual S to avoid oversizing.[59]

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[58] Green Building Advisor. February 25, 2021. "Design Temperature vs. Degree Days." Available at: https://www.greenbuildingadvisor.com/article/design-temperature-vs-degree-days ; Air Conditioning Contractors of America. August 2014. *ACCA Manual J® Residential Load Calculation Eighth Edition*. Available at: https://higherlogicdownload.s3.amazonaws.com/ACCA/8e4cf5b4-e984-4971-bb79-7889082c7cf2/UploadedImages/MJ8-Adden-E-Updated-Weather-Data-11Aug2014.pdf.

[59] Avoiding oversizing is important because oversizing of HVAC systems will cause the systems to cycle very often and run inefficiently. This will also cause wider temperature swings, making occupants uncomfortable. Further, oversizing will increase the cost of HVAC systems.

For example, Manual S recommends furnaces and boilers be sized 100 to 140 percent of the total heating load (that is calculated based on Manual J, mentioned above). For heat pumps, Manual S recommends a system be sized 125 percent of the total cooling load.[60] While it is not straightforward to understand the upper limit of a heating system size relative to the total cooling load, other organizations provide guidance on heat pump sizing in terms of percentage of heating load. For example, Northeast Energy Efficiency Partnerships (NEEP) recommends that "[i]f you are planning for the heat pump to provide the full load, check that Percent Design Load Served is between 90%-120%."[61] Further, the New York State Energy Research and Development Authority (NYSERDA) has the following requirement for the sizing of whole-home heat pumps regarding NYSERDA's ASHP program: "Each Whole-House Solution ASHP System project application must include a completed Manual J or equivalent energy simulation program or calculator demonstrating the installed system has a full-load heating capacity of between 90% and 120% of peak heating load."[62] Based on these practices and to err on the conservative side, we assume that heat pumps will be sized at the higher end of the heating capacity threshold (120 percent of design loads).

According to ASHRAE, winter design temperatures are approximately -6°F for Minneapolis and St. Paul, Minnesota, -8°F for Rochester, and -12°F for Duluth.[63] The population-weighted design temperature among these large cities is approximately -7°F. Assuming a 120 percent capacity oversizing factor, this means that a system designed based on Manual J and Manual S to meet the weighted average design temperature has enough capacity to meet the load down to approximately -21°F. We used this temperature to analyze the winter peak load impacts under extreme weather events. The end-use load shapes used in our analysis primarily rely on the NREL EULP database, which uses actual 2018 weather conditions. The lowest temperature was, on average, approximately -15°F across the state. Thus, we estimated the potential additional heating demand required to meet the heating load beyond -15°F down to approximately -21°F. We estimated that heating loads for all-electric whole-building heat pumps are about 27 percent higher and heating loads for electric resistance heaters and GSHPs are 7 percent higher than normal winter weather conditions.

[60] Davis, Wes. 2009. "Reviewing HVAC Designs for Compliance with ACCA Manual S." Available at: https://media.iccsafe.org/news/eNews/2009v6n8/hvac.pdf.

[61] Northeast Energy Efficiency Partnerships. 2022. *Users Guide: Cold Climate Heat Pump Sizing Support Tools*. Page 3. Available at: https://ashp-production.s3.amazonaws.com/NEEP_ccASHP+Heating+Visualization+User+Guide_v2.2_TRC_04.01.22.pdf.

[62] New York State Energy Research and Development Authority (NYSERDA). April 2019. *Air Source Heat Pump Program Manual*. Version 4. Available at: https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt000000Dq4lbEAB.

[63] ASHRAE Climatic Design Conditions for Minneapolis-St Paul: (http://ashrae-meteo.info/v2.0/index.php?lat=44.883&lng=-93.229&place=%27%27&wmo=726580), Rochester (http://ashrae-meteo.info/v2.0/index.php?lat=43.904&lng=-92.492&place=%27%27&wmo=726440), and Duluth (http://ashrae-meteo.info/v2.0/index.php?lat=46.837&lng=-92.183&place=%27%27&wmo=727450).

4.1.1.3 Transmission and distribution investments

We estimated net incremental peak loads and the associated electric utility T&D investments under our scenarios beyond what would be expected under a baseline load forecast (based on the EIA's 2023 AEO forecast). We assumed that T&D costs would be incurred if our projected winter peak loads exceed the highest peak loads under the baseline forecast. This approach is conservative and likely overestimates necessary T&D investments for the following two reasons:

- First, and most importantly, our analysis does not consider any future investments that would be required to support the adoption of EVs. We expect that EVs and EV charging stations will lead to substantial T&D investments in the future. Summer peak loads from EVs that are coincident with the summer system peak (around late afternoon to early evening) are likely to be substantially higher than winter peak loads from EVs that are coincident with the winter system peak (early morning) because many EVs are expected to be fully charged by early morning. Some recent studies show that revenues from EVs could outweigh the necessary T&D investments.[64] This means that the T&D system could have a substantial increase in headroom that would be paid for by additional revenues from EVs while remaining available to accommodate building electrification during the winter.
- Secondly, our approach does not consider any existing T&D headroom (that is, the existing T&D capacity above the current summer peak) and thus overestimates investments in the near term. However, the overall results in the long term through 2050 should provide a reasonable picture of the expected investments (excluding any impacts from EV-related investments).

We took different approaches to estimating transmission investments and distribution investments. For transmission investments, our approach focuses on the system-wide peak loads across all sectors because the transmission system serves large areas. The highest peak loads during such system-wide peak often occur at different times than the highest peak loads for each sector. For example, the residential sector in Minnesota is already winter-peaking, but the overall system is summer-peaking. On the other hand, for distribution investments, our approach estimates peak loads for each sector (that are the highest peak loads for each sector) and the associated investments. We took this approach because distribution investments occur at the local level. We expect that this aggregation by sector provides a high-level, but reasonable, approximation of distribution investments.[65]

We then applied our estimate of T&D costs in terms of dollars per kW-year to the net peak load impacts and estimated the total T&D investments. Xcel Energy currently uses avoided T&D costs of approximately $17.2 per kW-year (in $2022) to assess the benefits of energy efficiency in its Energy

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[64] Nadel, Steven. 2024. "Charging Ahead: How EVs Could Drive Down Electricity Rates." The American Council for an Energy Efficient Economy. January 10. Available at: https://www.aceee.org/blog-post/2024/01/charging-ahead-how-evs-could-drive-down-electricity-rates.

[65] In reality, distribution investments often occur at the feeder level. Our analysis does not show location-specific investments that are needed for distribution planning.

Conservation Optimization (ECO) Triennial Plan.[66] This estimate is one of the lowest avoided T&D cost estimates across many jurisdictions.[67] Thus, to be conservative (in terms of the results of our analysis), we made a simplified assumption by doubling Xcel's T&D avoided costs, which results in an estimate of approximately $34 per kW-year.

Finally, we converted the annual net T&D investments into T&D delivery rates and combined them with our forecast of electricity supply rates to develop the total electricity rates for the residential sector for the two policy scenarios. We used these rate forecasts for our residential bill impact analysis (discussed in Section 6.1). Our rate analysis started with the development of an electricity rate forecast for a business-as-usual or baseline case for Minnesota based on the current average electricity rate and the AEO 2023 electricity rate forecast for the Midwestern region. We then adjusted the baseline T&D delivery rate forecast by taking into account (a) the upward rate pressure from the net incremental T&D investments due to building electrification and (b) the downward rate pressure stemming from increased electricity sales due to building electrification. We assume that the electricity supply rate forecast is the same across all scenarios.

4.2 Results

4.2.1 Winter Peak Load

Table 7 presents the total peak load projections including the impacts of extreme weather effects for the entire state (for the residential, commercial, and industrial sectors) for each scenario for 2021, 2030, 2040, and 2050. Under the Full Electrification scenario, without factoring in demand response or other peak-reduction measures, we project that system-wide peak loads will increase by 93 percent from about 14.2 GW today to 27.5 GW by 2050 with an annual average growth rate of 2.3 percent. Under the Electrification + Alternative Fuels, we project that system-wide peak loads will increase by 72 percent from the current level to 24.5 GW by 2050 with an annual average growth rate of 1.9 percent. We expect Minnesota's electric grid will transition to winter-peaking around 2029 under the Full Electrification scenario, while the grid will not transition to winter-peaking under the Electrification + Alternative Fuels scenario until around 2038.[68] As shown below, the Full Electrification case results in up to 32 percent greater peak load than the Electrification + Alternative Fuels scenario, and in 2050 has a peak load of 27.5 GW, 3 GW (or 12 percent) greater than the Alternative Fuels case. The Full

[66] Xcel Energy. 2023. *2024–2026 ECO Triennial Plan*, Attachment A – Public. June 29. Docket No. E,G002/CIP-23-92. Available at: https://efiling.web.commerce.state.mn.us/verification/viewServedDocument.do?method=showSubmissionInfo&reqFrom=viewServedDocuments&selectedId=183217&docketNumber=E002,G002/CIP-23-92&showList=true#.

[67] For example, see Mendota Group. 2014. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments*. Available at: https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf.

[68] While the analysis suggests the grid will transition to winter-peaking in the years provided, we did not project any new cooling loads associated with heat pump adoption, meaning the transition point may be slightly later than noted above.

Electrification scenario has a 2050 system peak that is close to double that of 2021, while the Electrification + Alternative Fuels scenario projects a system peak that is about 10.3 GW, or about 72 percent, greater than the peak in 2021. We estimate approximately 54 and 48 percent of the total winter peak load in 2050 is caused by electrification of the major end uses for the Full Electrification and Electrification + Alternative Fuels scenarios, respectively.

Table 7. Projected electric winter peak loads in Minnesota through the study period (MW)

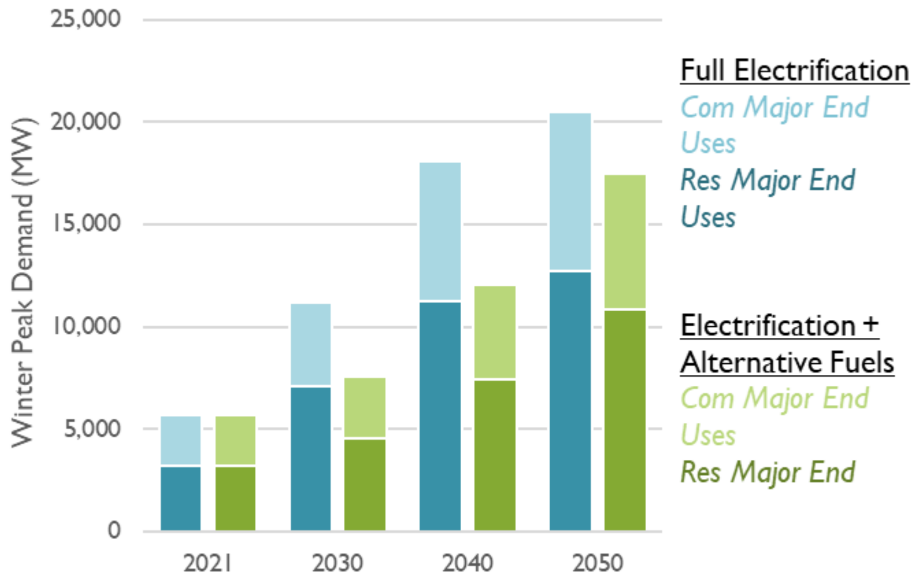
Scenario	2021		2030	2040	2050	Annual growth rate (%)
	Summer (coincident)	Winter (non-coincident)				
Full Electrification	14,256	11,984	17,729	24,883	27,535	2.3%
Electrification + Alternative Fuels	14,256	11,984	14,813	18,878	24,521	1.9%
Difference	**-**	**-**	**20%**	**32%**	**12%**	

Figure 21 presents winter peak load impacts by scenario and year for all major end uses. For the residential sector, major end uses include space heating, water heating, cooking, and clothes drying. For the commercial sector, major end uses include space heating, water heating, and cooking.

In the Full Electrification scenario, winter peak loads from major end uses in the residential and commercial sectors are projected to increase by more than a factor of three, from 5.6 GW today to over 20 GW by 2050. The residential peak loads are projected to increase by about 300 percent while the commercial peak loads are projected to increase by about 220 percent. We project that most of the peak load increase is driven by fuel-switching from natural gas heating to heat pumps for space heating; in 2050 about 70 percent of the coincident peak (or 19 GW) is from residential and commercial heat pumps alone. The projected peak load of major end uses in the Full Electrification scenario is about 17 percent greater than in the Electrification + Alternative Fuels scenario in 2050.

In the Electrification + Alternative Fuels scenario, winter peak load impacts from major end uses in the residential and commercial sectors are projected to increase from 5.6 GW today to over 17.5 GW by 2050 (or by 208 percent). The residential peak loads are projected to increase by about 240 percent while the commercial peak loads are projected to increase by about 170 percent. While most of the peak load increase is due to greater heat pump adoption, the retention of natural gas backup tempers the peak load increase; in 2050, about 66 percent of the system peak (or 16.2 GW) is from heat pumps. These peak load estimates increase at an average annual load growth rate of 2.3 percent in the Full Electrification scenario and 1.9 percent in the Electrification + Alternative Fuels scenario.

Figure 21. Winter peak load impacts between scenario for major end uses



The projected electric rates may appear dramatic and unprecedented. However, they are in fact very similar to what Minnesota's grid experienced in the 1990s and the 2000s until right before the 2008 economic recession.[69] According to EIA's 861 database, the total aggregated, non-coincident summer peak loads for Minnesota grew from approximately 16.8 GW in 2000 to 19 GW in 2007, with an average annual growth rate of 1.9 percent per year.[70] During the same timeframe, annual electricity sales also grew from 60,000 GWh to about 69,500 GWh with an average annual growth rate of 2 percent per year, as shown in Figure 22. Annual energy sales growth rates were even higher prior to 2000. In the 90s, the load growth (especially after the early-90s recession) was high with an average growth rate of 2.8 percent, which implies that the peak load growth during this time period may have been equally high. The higher electric load growth rates experienced in the recent past indicate that the low load growth we experienced in the 2010s through today has been a unique time period in the history of the electric industry.

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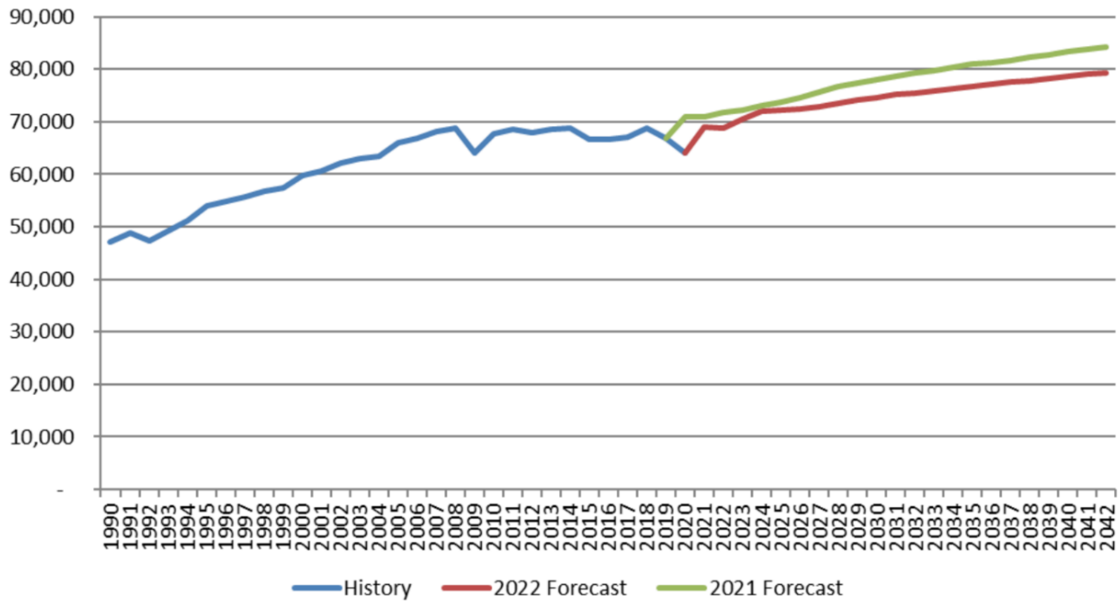
[69] Further, it is likely that the electricity growth rates in the 80s were much higher above 3 or even 4 percent per year. While we did not investigate the load growth in the 80s for Minnesota, a recent electrification study for Maryland "*An Assessment of Electrification Impacts on the Maryland Electric Grid"* by the Brattle Group revealed that the annual load growth rates in the 80s was 4.9 percent per year while the study estimated relatively low annual electric peak growth rates for various aggressive electrification scenarios over the next 7 years, ranging from about zero percent (with aggressive levels of demand-side management and dual-fuel heating) to slightly over 2 percent per year (with aggressive electrification with legacy heat pump technologies). See details of this study at: https://www.psc.state.md.us/wp-content/uploads/MDPSC-Electrification-Study-Report.pdf. Finally, an analysis of historical electricity demand by EIA shows that average annual growth rates during the 70s for the entire United States were greater than during the 90s. See U.S. EIA. 2013. "U.S. economy and electricity demand growth are linked, but relationship is changing." Available at: https://www.eia.gov/todayinenergy/detail.php?id=10491.

[70] U.S. EIA. Form-EIA 861 database. Available at: https://www.eia.gov/electricity/data/eia861/.

Figure 22. Minnesota historical and forecasted annual retail sales (GWh)



Source: State Utility Forecasting Group. 2022. 2022 MISO Energy and Peak Demand Forecasting for System Planning. Figure 12.

Lastly, it is important to note that our winter peak load forecasts do not include any impacts of building load flexibility/demand response measures associated with space and water heating end uses such as smart thermostats and direct load control of storage water heaters. Nor do those forecasts include any other demand response for other end uses (e.g., lighting, ventilation, and motors for commercial buildings). The potential impact of load flexibility measures is substantial. For example, a recent demand response potential study by Xcel Colorado found approximately 540 MW of winter peak load reduction potential through load flexibility measures through 2030. This represents about 12 percent of the utility's projected 2030 winter peak load. If we apply this factor to the results of our analysis for 2050, the total peak load savings would be 2.5 GW to 2.8 GW. As mentioned above, we conducted a high-level assessment of demand response potential estimates for space and water heating end uses as a sensitivity analysis, the results of which are found in Section 7.2.

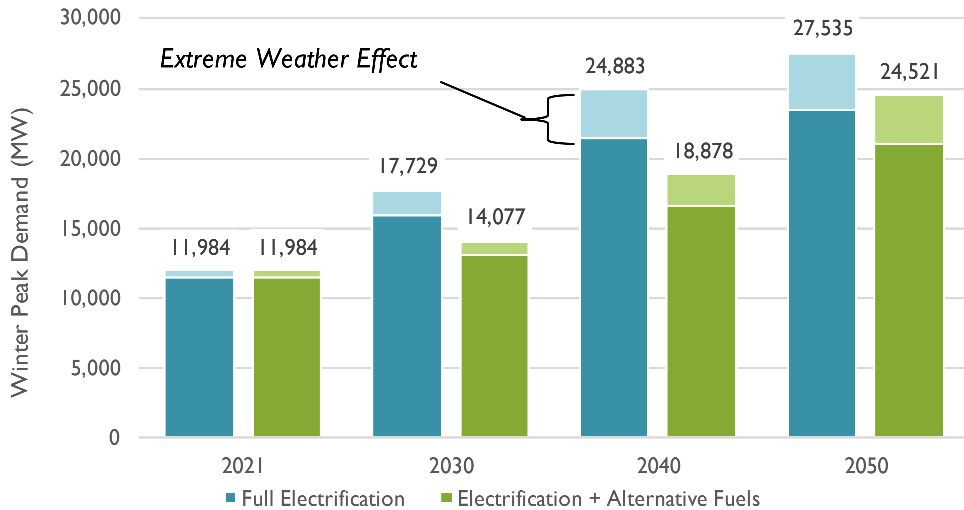
4.2.2 Extreme weather events

To provide a safety factor for grid planning purposes, our peak load projections presented above account for a level of extreme weather (e.g., cold snaps). This means that we have increased the capability of space heating to meet the total space heating load down to approximately -21°F, as described in the section above.[71] Figure 23 shows Minnesota's system-wide winter peak load by scenario and year, including the extreme weather effect appended above each bar. In total, we project that extreme weather events increase winter peak demand by about 4 GW from 23.4 GW to 27.5 GW by 2050 under the Full Electrification scenario, and by about 3.5 GW from 21 GW to about 24 GW under

[71] It is important to note that the assumed heating capacity can also meet heating loads even below -21°F partially, while such extreme weather events are rare and do not last long.

the Electrification + Alternative Fuels scenario. These impacts represent 17 percent peak load increases in both scenarios.

Figure 23. Winter peak load impacts for all end uses by scenario



4.2.3 Peak day load profiles

On a peak day, most of this increased electricity demand for both scenarios is a result of heat pump space heating.[72] The following figures compare current and forecast peak day load profiles for both scenarios. Figure 24 compares the peak day load profiles for the current day and in 2050 under the Electrification + Alternative Fuels scenario. A substantial amount of new heat pump demand drives this peak load increase; by 2050 there is an additional 8.5 GW of residential space heating demand and an additional 4 GW of commercial space heating demand. This 12.5 GW of new heating demand, coincident with the system peak, is about 3.5 times the current space heating demand and more than double the total winter peak demand in the 2021 baseline. The result is a system peak demand in 2050 of 24.5 GW.

[72] See Section 5.1.1 for backup and supplemental heating assumptions.

Figure 24. 2021 and 2050 peak day load profiles – Electrification + Alternative Fuels

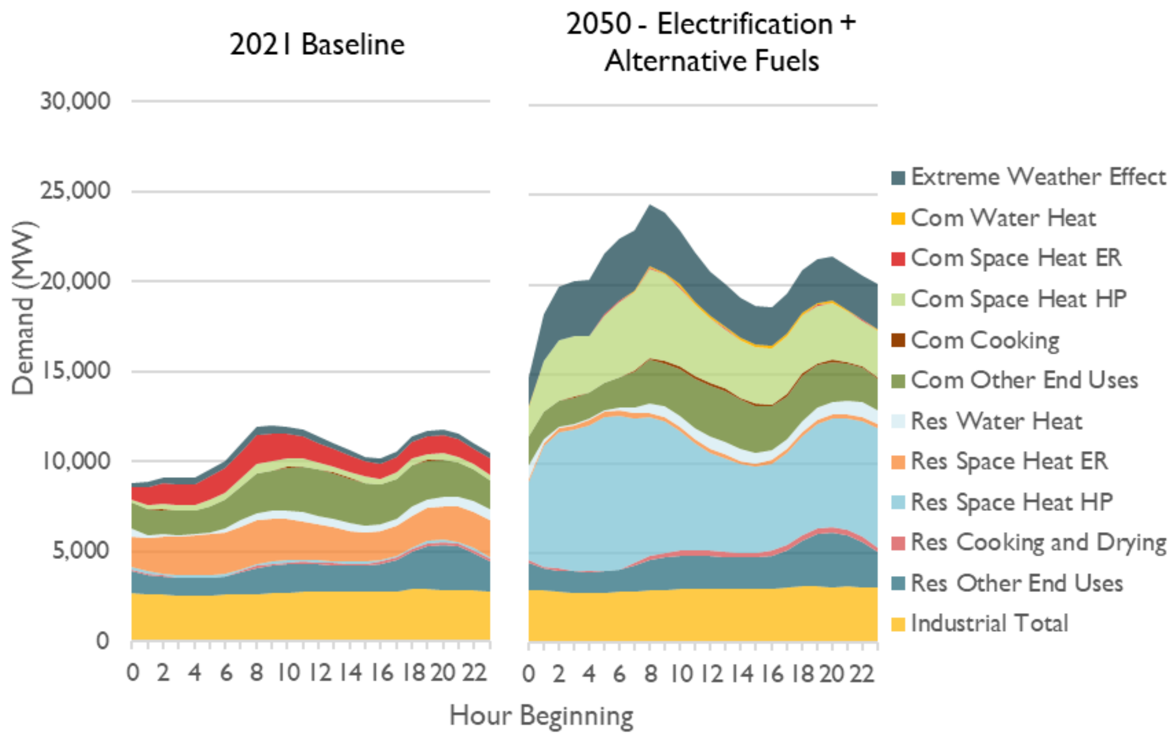
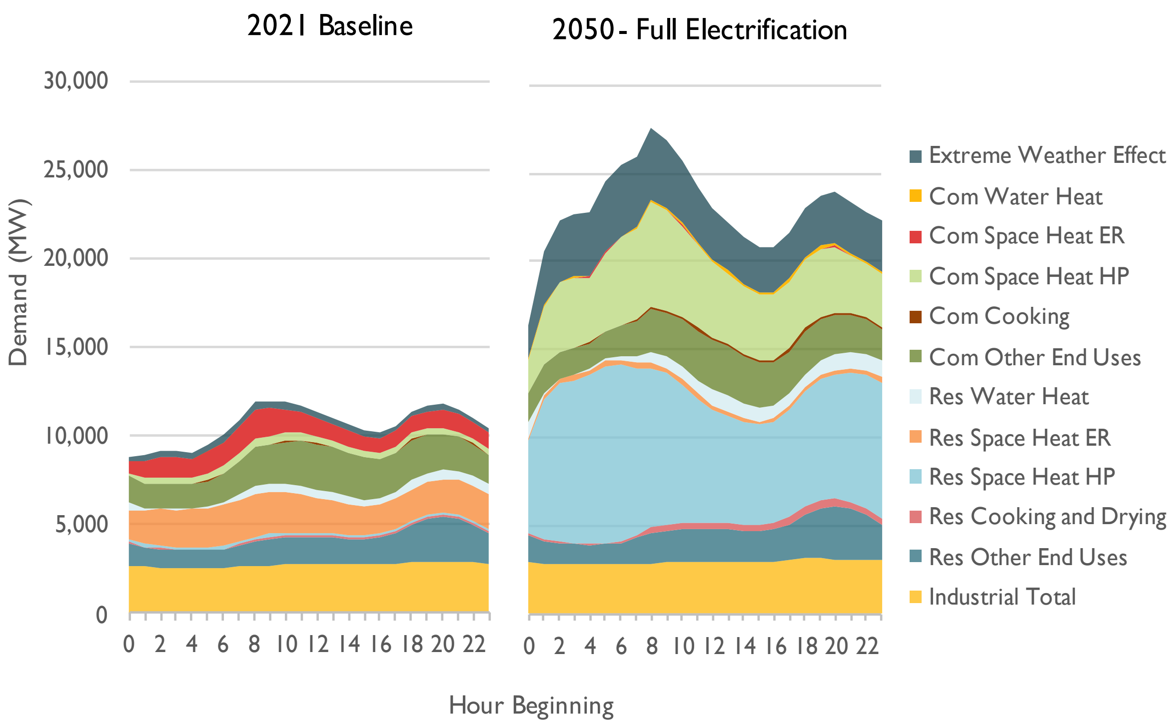


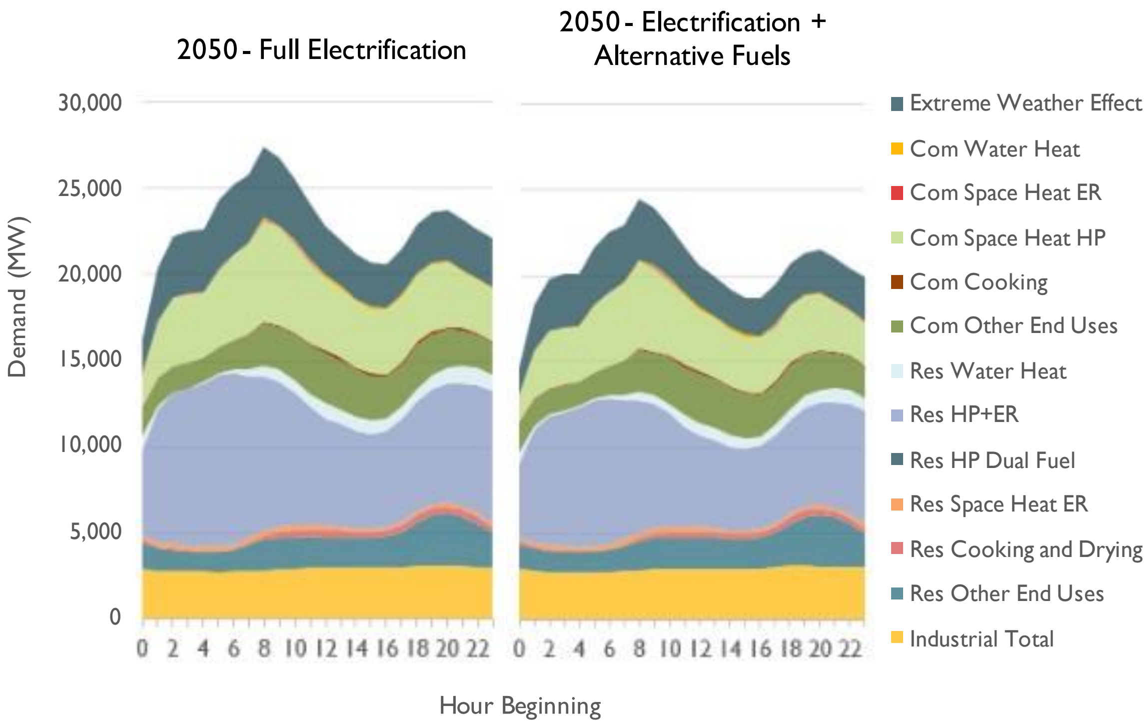
Figure 25 below presents similar results, comparing the 2021 baseline against the Full Electrification results in 2050. Under this scenario, peak demand is higher yet, with new residential space heating demand of 10.4 GW and new commercial space heating demand of 5.2 GW, for a total of 15.5 GW of new space heating demand alone. This level of additional space heating demand is about 4 times the space heating demand in the 2021 baseline and 30 percent higher than the total winter peak demand in the 2021 baseline. This results in a system peak of 27.5 GW in 2050.

Figure 25. 2021 and 2050 peak day load profiles – Full Electrification



Finally, Figure 26 compares the 2050 results for both scenarios. The peak load under the Electrification + Alternative Fuels scenario is 12 percent lower than the peak load under the Full Electrification scenario due to the higher adoption of dual-fuel heat pumps, which utilize natural gas backup under periods of extreme cold. In contrast, under the Full Electrification scenario, more heat pumps are backed up with electric resistance heating, which exacerbates the effect that extreme cold has on the electric grid. Under normal winter weather conditions, the Full Electrification scenario has a peak load that is 2.4 GW greater than the Electrification + Alternative Fuels scenario. However, extreme cold causes the difference between peak load values to increase to over 3 GW.

Figure 26. 2050 peak day load profiles - Full Electrification (left) and Electrification + Alternative Fuels (right)



4.2.3.1 Transmission and distribution investments

As mentioned above, our analysis of T&D costs is conservative because it does not account for the impacts of EVs. We expect that T&D investments accommodating EVs will provide additional T&D headroom for building electrification in the winter season. Our T&D cost analysis is also conservative for another reason: our analysis did not assume any T&D headroom in the existing T&D system, and thus we counted T&D costs for building electrification when the projected peak loads under the policy scenarios exceed the projected peak loads in the baseline forecast.

Figure 27 presents our estimates of net T&D investments by scenario. Under the Full Electrification scenario, we expect that annual net T&D investments associated with building electrification will gradually increase through 2029 reaching about $50 million annual investments and then grow rapidly afterwards through 2040. After 2040, annual net T&D investments will keep increasing at a slower rate and then reach the highest annual net T&D cost of about $300 million in 2045. Under the Electrification + Alternative Fuels scenario, we project that annual net T&D costs increase gradually and reach about $50 million in 2038. After this year, we project annual net T&D costs will rapidly increase and reach $216million in 2050, which is 30 percent lower than the annual cost under the Full Electrification scenario. Overall, we estimate that these investments total approximately $2.6 billion in present value

(PV) through 2050 under the Full Electrification scenario and $1 billion (PV) under the Electrification + Alternative Fuels scenario, as shown in Table 8.[73]

Figure 27. Projected net annual T&D investments by scenario

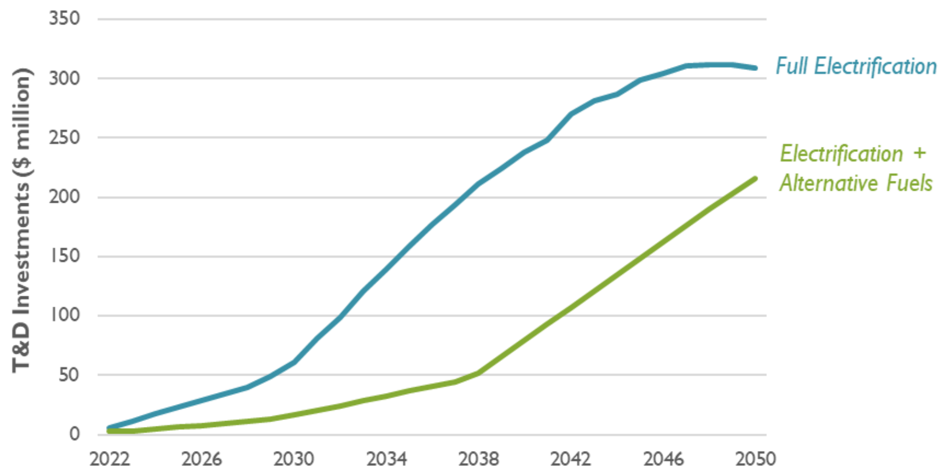


Table 8. Total present value of net T&D investments by scenario and sector ($ million, PV)

	Residential	Commercial	Total
Full Electrification	2,059	561	2,620
Electrification + Alternative Fuels	903	141	1,034

Table 8 also presents investments by sector. As shown in this table, most of the investments (79 percent for the Full Electrification scenario and 87 percent for the other scenario) are for the residential sector. This is because the expected winter peak load increase due to building electrification is greater for this sector than for the commercial sector and because the residential sector is already winter-peaking in the state, while the commercial sector will not become winter-peaking until 2042 in the Full Electrification scenario and will remain summer-peaking under the Electrification + Alternative Fuels scenario. This means that the expected distribution investments associated with commercial building electrification are substantially lower than with residential building electrification.

4.2.3.2 Electricity rate projection

Figure 28 presents our projection of average residential electricity delivery rates (including customer charges) through 2050 by scenario. As shown in this figure, we project that the delivery rates for both scenarios will be approximately 9 to 11 percent lower on average than the delivery rates expected for the baseline case. Further, we found that the rates under the Full Electrification case will be slightly

[73] This analysis uses a 3.3 percent real discount rate which the societal discount rate used in the Minnesota Test as approved by the Deputy Commissioner: In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, dated March 31, 2023, in Docket No. E,G999/CIP-23-46.

lower than the rates under the Full Electrification + Alternative Fuels case. This analysis shows that the effect of the increased revenues due to building electrification is greater than the effect of the increased T&D investments due to building electrification. Table 9 presents a detailed comparison of levelized electricity delivery rates by scenario through the study period.[74]

Figure 28. Projected residential electricity delivery rates by scenario

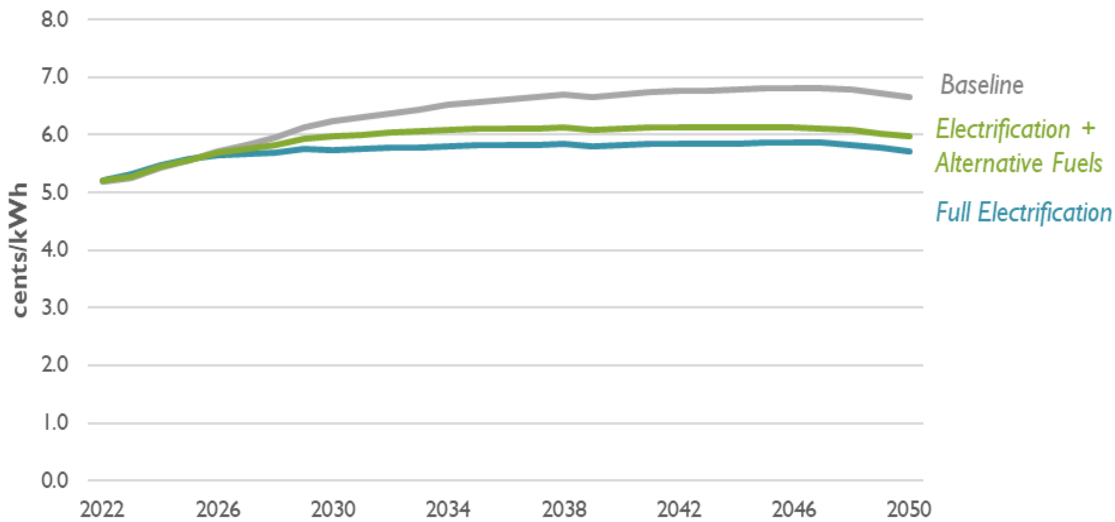


Table 9. Comparison of levelized electricity all-in delivery rates by scenario (cents/kWh)

	Baseline	Increased revenue due to electrification	Net incremental T&D costs due to electrification	Total delivery rates	Rate change (% of baseline)
Full Electrification	6.66	-1.12	0.35	5.89	-11.6%
Electrification + Alternative Fuels	6.66	-0.74	0.16	6.08	-8.7%

5. Resource Cost Analysis

This section presents the results of the resource cost analysis. For this analysis, Synapse investigated the upfront costs customers would pay under each decarbonization scenario. We developed resource cost estimates for customers based on Minnesota-specific studies and data, national data, and studies from other jurisdictions. These costs include the cost of new electrification equipment such as heat pumps and HPWHs, as well as new fossil fuel equipment. More specifically this analysis investigates resource costs for commercial and residential customers, including costs of ASHPs, dual-fuel heat pumps, GSHPs,

[74] We levelized the rate projections using a 3.3 percent real discount rate.

central air conditioners, HPWHs, electric panel upgrades, gas furnaces, gas water heaters, and electric and gas cooking and drying appliances.

5.1 End-Use Equipment Costs

We estimated current total per-unit installed costs for electric and gas end-use equipment for residential and commercial buildings.[75] These total upfront installed costs include equipment and labor costs but exclude ongoing operation and maintenance costs. We did not include energy efficiency retrofits, such as building envelope upgrades to reduce peak-load impact of electrification, because we assumed the same weatherization improvements in both scenarios.

The ways in which costs are spread among customers are a matter of public policy and are not considered here. These considerations may include incentives, weatherization and utility demand-side management programs, rate design, and tax policy. Specifically, we did not include federal, state, or utility incentives in our cost projections, though these incentive programs provide substantial opportunities to reduce upfront costs of efficient electric equipment.

To calculate costs through 2050, we forecasted future total installed costs of these systems using data from NREL's Electrification Future Study's moderate advancement scenario.[76] Heat pump costs fall, in real terms, over the study period to reflect the increasing maturity of the technology along with technical and market advances as the equipment becomes much more widely adopted. In comparison, gas furnace and boiler technologies are largely mature and thus we project stable costs through the study period.

5.1.1 Space Heating

Table 10 shows the forecasted total installed costs for residential equipment through 2050. These costs represent per-household costs in the year households purchase new equipment. We developed the current cost estimates for residential heat pumps and gas furnaces primarily based on a 2022 study by Center for Energy and Environment which analyzed ASHPs as a replacement for central air conditioning (AC) in Minnesota.[77] These costs are based on average contractor bids for heat pump equipment sized for single-family households. Space heating heat pumps with electric resistance backup displace the need to pay for separate air conditioning and gas heating furnace or boiler systems, thus offering potential cost savings on purchasing other equipment. To compare gas and electric system costs on an

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[75] While the focus of this section is on the comparison of gas and electric equipment costs, this analysis did include the costs of electric resistance, propane, and fuel oil systems.

[76] Mai, T. et al. 2017. *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050*. National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf.

[77] Center for Energy and Environment (CEE). 2022. *Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning*. Available at: https://mn.gov/commerce-stat/pdfs/187376_CEE_HP-for-AC_Report_Final%20Secure.pdf.

apples-to-apples basis, we included the cost of new central air-conditioning equipment in the total household gas heating system costs. For gas-heating households switching to dual-fuel heat pumps, we included the costs of backup furnace replacement based on conservative end-of-life gas equipment turnover rates.[78]

Because households switching to whole home all-electric heat pumps will typically require a larger heat pump capacity compared to dual-fuel-heating households who retain a backup heating system, we assumed dual-fuel heat pumps will be cheaper than all-electric heat pumps. Finally, we developed estimates for GSHP costs based on a 2017 NYSERDA study of GSHP costs and incremental costs from the Minnesota Technical Reference Manual.[79,80]

Table 10. Synapse projection of average total installed costs of residential space heating equipment in Minnesota ($2022/household)

Residential equipment	2022	2030	2040	2050
Gas furnace and central AC	$10,809	$10,809	$10,809	$10,809
All-electric heat pump	$15,800	$14,745	$13,426	$12,108
Dual-fuel heat pump	$13,000	$12,132	$11,047	$9,962
GSHP	$31,447	$29,348	$26,723	$24,098

Table 11 shows the forecasted commercial space heating costs, presented on a per-thousand-square-feet basis to align with the commercial building stock accounting methodology in the BDC. Synapse developed these cost estimates primarily from a 2021 building electrification study for Los Angeles by Inclusive Economics.[81] The Inclusive Economics study provides per-square-foot end-use electrification estimates for large and small commercial buildings.[82] To apply these costs across all commercial buildings in Minnesota, we used NREL's ComStock data to develop weighted electrification costs based

[78] Note that for gas-heating households adopting dual-fuel heat pump systems, we do not include the cost of air-conditioning equipment in the costs of backup gas equipment replacement, because the dual-fuel heat pump serves both heating and cooling.

[79] NYSERDA. 2017. *Renewable Heating and Cooling Policy Framework*. Available at: https://www.nyserda.ny.gov/About/Publications/Research-and-Technical-Reports/Clean-Heating-and-Cooling-Reports.

[80] MN Department of Commerce. 2023. *Minnesota Technical Reference Manual for Energy Conservation Improvement Programs, Version 4.0*. Available at: https://mn.gov/commerce-stat/trm/releases/4.0.pdf.

[81] Jones, Betony. 2021. *Los Angeles Building Decarbonization: Community Concerns, Employment Impacts, Opportunities*. Inclusive Economics. Available at: https://www.nrdc.org/sites/default/files/los-angeles-building-decarbonization-jobs-impacts-report-20211208.pdf.

[82] The Inclusive Economics Study uses a threshold of 50,000 square feet to categorize large versus small commercial buildings.

on the breakdown of Minnesota commercial building stock by size and adjusted for the difference in regional labor and equipment costs based on RSMeans.[83,84]

To calculate costs for commercial dual-fuel heating, we scaled the heat pump electrification costs to align with the residential equipment cost differentials between heat pumps and dual-fuel heat pumps (Table 11). To estimate gas equipment costs, we used measure cost data for commercial heat pumps and gas furnaces from the California Technical Reference Manual (CA eTRM) to scale down the electrification costs.[85] As with the residential costs, we assumed that the gas heating equipment costs include the costs of air-conditioning, except for buildings with dual-fuel ASHPs replacing their gas backup systems. Finally, we scaled the heat pump costs to estimated commercial GSHP costs based on the 2017 NYSERDA study of GSHP costs.[86]

Table 11. Synapse projection of average commercial space heating equipment costs in Minnesota (2022$/thousand square feet)

Commercial equipment	2022	2030	2040	2050
Gas furnace and AC	$19,854	$19,854	$19,854	$19,854
All-electric heat pump	$21,719	$19,195	$17,091	$15,777
Dual-fuel heat pump	$17,870	$15,793	$14,063	$12,981
GSHP	$26,094	$23,062	$20,534	$18,955

5.1.2 Water heating

Table 12 shows the forecasted residential water heating costs through 2050. Synapse developed these cost estimates using measure data from the California eTRM.[87] From this data Synapse calculated average equipment and labor costs and adjusted the costs using RSMeans locational cost factors for California and Minnesota.[88] While the costs of HPWHs decline over time to reflect technology and market improvements, electric and gas water heater costs are stable throughout the study period.

83 National Renewable Energy Laboratory. 2023. *ComStock Public Datasets: Metadata.* End Use Load Profiles for the U.S. Building Stock. Available at: https://comstock.nrel.gov/ .

84 RSMeans. 2019. *RSMeans City Cost Index*. Available at: https://www.rsmeans.com/rsmeans-city-cost-index.

85 California eTRM. 2023. Available at: https://www.caetrm.com/measure/SWWH013/03/value-table/257792/.

86 NYSERDA. 2017. *Renewable Heating and Cooling Policy Framework*. Available at: https://www.nyserda.ny.gov/About/Publications/Research-and-Technical-Reports/Clean-Heating-and-Cooling-Reports.

87 California eTRM. 2023. Available at: https://www.caetrm.com/measure/SWWH013/03/value-table/257792/.

88 RSMeans. 2019. *RSMeans City Cost Index*. Available at: https://www.rsmeans.com/rsmeans-city-cost-index.

Table 12. Synapse projection of average total installed costs of residential water heating equipment in Minnesota (2022$/household)

Residential equipment	2022	2030	2040	2050
HPWH	$2,501	$2,124	$1,730	$1,573
Electric water heater	$847	$847	$847	$847
Gas storage water heater	$1,107	$1,107	$1,107	$1,107
Gas tankless water heater	$2,094	$2,094	$2,094	$2,094

Table 13 shows Synapse's forecasted total installed costs of commercial water heating equipment. As with commercial space heating, these costs are calculated based on Inclusive Economics' building electrification study for Los Angeles.[89] We used the same methodology to develop weighted cost estimates based on the share of large and small commercial buildings in Minnesota. As we did for space heating, we estimated electric and gas water heater costs by scaling the HPWH costs using water heater measure data from the California eTRM.

Table 13. Synapse projection of costs of commercial water heating equipment in Minnesota (2022$/thousand square feet)

Commercial equipment	2022	2030	2040	2050
HPWH	$567	$500	$431	$373
Electric water heater	$234	$234	$234	$234
Gas storage water heater	$305	$305	$305	$305

5.1.3 Cooking and Drying

Table 14 and Table 15 show forecasted costs of cooking and drying equipment for residential and commercial buildings through 2050. As these technologies are largely mature, we assumed the costs for all equipment types remain stable over the study period. We estimated the residential cooking costs using measure data from the California eTRM. Commercial electric cooking costs are based on commercial cooking electrification costs from Inclusive Economics' building electrification study.[90] We estimated the gas cooking equipment costs by applying a scaling factor based on cooking equipment cost data from the California eTRM. The costs for residential clothes dryers are from the Minnesota Technical Reference Manual.[91]

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[89] Jones, Betony. 2021. *Los Angeles Building Decarbonization: Community Concerns, Employment Impacts, Opportunities*. Inclusive Economics. Available at: https://www.nrdc.org/sites/default/files/los-angeles-building-decarbonization-jobs-impacts-report-20211208.pdf.

[90] Jones, Betony. 2021. *Los Angeles Building Decarbonization: Community Concerns, Employment Impacts, Opportunities*. Inclusive Economics. Available at: https://www.nrdc.org/sites/default/files/los-angeles-building-decarbonization-jobs-impacts-report-20211208.pdf.

[91] MN Department of Commerce. 2023. *Minnesota Technical Reference Manual for Energy Conservation Improvement Programs, Version 4.0*. Available at: https://mn.gov/commerce-stat/trm/releases/4.0.pdf.

Table 14. Synapse projection of average total installed costs of residential cooking and drying equipment in Minnesota (2022$/household)

Residential equipment	2022	2030	2040	2050
Electric clothes dryer	$911	$911	$911	$911
Gas-fired clothes dryer	$717	$717	$717	$717
Electric range	$991	$991	$991	$991
Gas range	$962	$962	$962	$962

Table 15. Synapse projection of average total installed costs of commercial cooking equipment in Minnesota ($2022/thousand square feet)

Equipment	2022	2030	2040	2050
Electric range	$20	$20	$20	$20
Gas range	$18	$18	$18	$18

5.2 Panel Upgrade Costs

One potential challenge of widespread building electrification is that older homes and buildings may require electric panel upgrades to support higher electric loads. Our analysis includes the costs of potential electric panel upgrades for residential buildings, but not for commercial buildings. This is primarily because our analysis of the need for panel upgrades in both scenarios (based on the results of the building decarbonization analysis from Chapter 2) revealed that there is little difference in the number of panel upgrades for commercial buildings between the two scenarios, while there are noticeable differences for residential buildings.

Upgrading electrical service in households will be an important consideration for building electrification as more household load is served by electricity. Typically, upgrades will be required for lower amperage panels (less than 200 Amps) to convert to 200 Amps. We assumed that homes built prior to 1980 do not have sufficient electrical capacity and thus need to replace their electrical panels to undergo whole-home electrification retrofits. However, we note that this is a conservative assumption because old homes will also need to upgrade their electrical panels if they install EV chargers, but our analysis does not include any EV-related analysis. Furthermore, due to the relatively small role of new construction in the overall pathway economic analysis, we did not account for new construction savings from avoiding the cost of installing gas piping or service lines to the street in the case of all-electric construction.

Table 16 shows average per-building panel upgrade costs for different types of residential buildings.[92] We used NREL's ResStock database to estimate the average number of units per building type in order

[92] Jones, Betony. 2021. *Los Angeles Building Decarbonization: Community Concerns, Employment Impacts, Opportunities*. Inclusive Economics. Available at: https://www.nrdc.org/sites/default/files/los-angeles-building-decarbonization-jobs-impacts-report-20211208.pdf.

to express these costs on a per-household basis.[93] Finally, we calculated a single weighted panel upgrade cost based on the breakdown of Minnesota residential building stock by type. On average across all building types, we calculated an upfront panel upgrade cost of $3,211 per unit.

Table 16. Residential electric panel upgrade costs by building type

Building type	Average panel upgrade cost *($2022/building)**	Average number of units per building**	Calculated panel upgrade cost *($/unit)*
Single Family	$3,565***	1	$3,565
Small Multifamily	$46,563	18	$2,587
Large Multifamily	$211,868	129	$1,642

*Source: *Jones, Betony. 2021. Los Angeles Building Decarbonization: Community Concerns, Employment Impacts, Opportunities. Inclusive Economics. Available at: https://www.nrdc.org/sites/default/files/los-angeles-building-decarbonization-jobs-impacts-report-20211208.pdf. Adjusted for regional cost differences based on RSMeans' regional cost factors.; ** NREL ResStock, ***Average of (Jones, 2021) and average panel upgrade cost of $2,500 from MN CEE. 2023. Minneapolis 1-4 Unit Residential Weatherization and Electrification Roadmap. Available at: https://www.mncee.org/sites/default/files/2023-02/Minneapolis%201-4%20Unit%20Residential%20Weatherization%20and%20Electrification%20Roadmap_Final%20%281%29.pdf*

There is no available data on how many homes in Minnesota currently lack a 200 Amp panel and thus will require panel upgrades if they fully electrify. As a proxy, Synapse assumed that homes built before 1980 will be more likely to require panel upgrades.[94] Using NREL's EULP database, we calculated that 55 percent of Minnesota households were built before 1980.[95]

To calculate the number of households that fully electrify and thus may require a panel upgrade, we calculated the number of households projected to install both electric space and water heating systems estimated based on our building decarbonization analysis (see Chapter 2) and gas system impact analysis (see Section 3.1). Of those, we estimated that 55 percent will have insufficient electrical capacity and will need to upgrade their electrical panels, based on the share of older homes in the state. On average, this results in approximately 30,000 panel upgrades per year through 2050. The number of panel upgrades is projected to increase annually from about 8,000–10,000 per year to about 37,000 units around 2030 in the Full Electrification scenario and 35,000 units in 2034 in the Electrification + Alternative Fuels scenario. After these years, the number of panel upgrades declines over time, except for the last few years in the Full Electrification scenario in which early replacement heat pumps increase the number of panel upgrades. We estimated that the total number of panel upgrades are 11 percent greater in the Full Electrification scenario than in the Electrification + Alternative Fuels scenario.

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[93] National Renewable Energy Laboratory. ResStock End Use Savings Shapes, 2022.1 Release. Available at: https://resstock.nrel.gov/datasets.

[94] Energy and Environmental Economics (E3). 2019. *Residential Building Electrification in California: Consumer economics, greenhouse gases and grid impacts.* Available at: https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf.

[95] National Renewable Energy Laboratory. ResStock End Use Savings Shapes, 2022.1 Release. Available at: https://resstock.nrel.gov/datasets.

5.3 Results

Both of the decarbonization scenarios analyzed in this study result in substantial spending by households and businesses on space heating systems, water heaters, and other appliances. Space heating heat pumps displace the need to pay for separate heating and cooling systems for homes and buildings that currently use or are planning to install central heating and cooling systems; thus, they avoid the need to purchase other heating or cooling equipment. HPWHs are more expensive upfront than traditional electric resistance or gas storage water heaters, but they cost less to operate. Displacing fossil-fuel-based appliances with electric appliances could also require upgrading the existing electrical wires and panels, especially for old buildings with a small electrical capacity. However, as mentioned above, the need for electrical panel upgrades could also be triggered by the need to install EV chargers.

Table 17 shows the present value of estimated capital costs between 2022 and 2050 for each scenario, using a 3.3 percent real discount rate.[96] The table breaks out the categories of equipment costs on a present-value basis by sector (residential and commercial buildings) and end use (space heating, water heating, or other equipment). Overall, the two scenarios have relatively similar present-value costs, well within the margin of error. Both scenarios will require substantial adoption of new electrification and decarbonization technologies. These costs do not reflect the potential to reduce gas system costs in the electrification cases, which are discussed in Chapter 3; or the potential increase in electric system costs, which are discussed in Chapter 4. Nor do they include discounts or incentives from utility, state, or federal programs. In present-value terms, the resource costs in the Full Electrification case total $8.65 billion, compared to $8.40 billion for the Electrification + Alternative Fuels case. As expected, the Electrification + Alternative Fuels case has slightly lower total capital costs overall, primarily because it relies more heavily on a hybrid approach with gas water heaters and dual-fuel heat pumps retaining existing backup systems, rather than an approach with HPWHs, more expensive whole-home heat pump options that require larger-size heat pumps, and more electric panel upgrades. The Full Electrification case assumes some early replacement of fossil fuel equipment with heat pumps in order to meet the net-zero targets. This strategy would impose additional costs on building owners or state- and ratepayer-funded programs. Residential and commercial non-panel equipment costs account for 90 percent of total end-user capital costs in both scenarios. Total equipment costs in the Alternative Fuels case are just 2 percent lower than in the Full Electrification case. Commercial space heating costs are the highest-cost category in both scenarios but vary by less than 1 percent between the two scenarios. Residential equipment costs drive the difference between the equipment costs in the two scenarios. Water heating, cooking, and drying end-use equipment costs account for 14 percent of total scenario costs. For both residential and commercial buildings, water heating, cooking, and drying equipment costs are roughly equivalent between the two scenarios.

Panel upgrade costs are 12 percent higher in the Full Electrification case, as expected. Panel upgrade costs are slightly lower in the Electrification + Alternative Fuels case because this case requires fewer

[96] This is the societal discount rate used in the Minnesota Test as approved by the Deputy Commissioner: In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, dated March 31, 2023, in Docket No. E,G999/CIP-23-46.

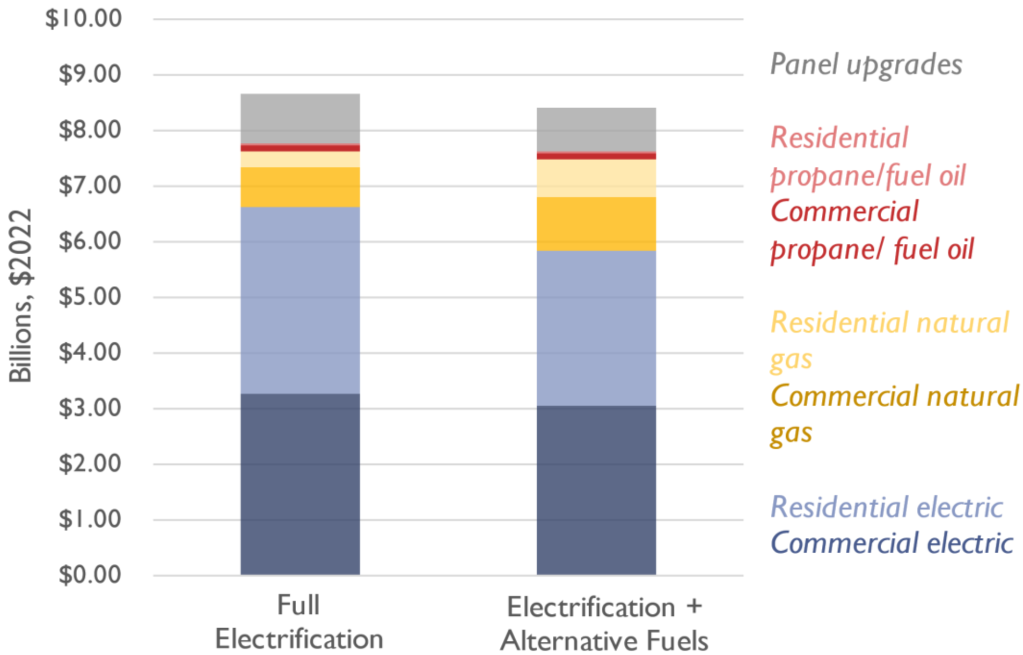
panel upgrade investments over the study period due to higher number of gas-heating-only customers. However, overall the two scenarios have roughly similar panel upgrade costs, since both cases require high levels of heat pump adoption and electrification of non-space heating end uses.

Table 17. Present-value capital costs under each decarbonization scenario (billions of $2022)

Sector	End Use	Full Electrification Scenario	Electrification + Alternative Fuels Scenario
Residential	Space Heat	$2.66	$2.51
Residential	Water Heat	$0.47	$0.46
Residential	Cooking and Drying	$0.56	$0.57
Residential	**Total equipment costs**	**$3.70**	**$3.54**
Commercial	Space Heat	$3.91	$3.94
Commercial	Water Heat	$0.14	$0.14
Commercial	Cooking	$0.01	$0.01
Commercial	**Total equipment costs**	**$4.06**	**$4.09**
Residential & Commercial	**Total equipment costs**	**$7.76**	**$7.62**
Residential	**Panel upgrades**	**$0.89**	**$0.78**
Total	**Total**	**$8.65**	**$8.40**

Figure 29 shows the breakdown of present-value resource costs for each scenario by equipment fuel and sector. Natural gas equipment costs in the Alternative Fuels case are almost double those in the Full Electrification case. In comparison, electric equipment capital costs decrease just by 12 percent in the Alternative Fuels case relative to the Full Electrification case. The lower investments in residential electric equipment are the primary driver of this change. In both scenarios, propane and fuel oil equipment represent only 2 percent of total scenario costs combined.

Figure 29. Present-value capital costs by fuel and sector for each scenario



6. Economic Analysis

6.1 Customer Bill Analysis

Synapse conducted an illustrative analysis of residential energy bills under both the Full Electrification and Electrification + Alternative Fuels scenarios. We conducted this analysis of annual bills through 2050 for residential customers in Minnesota living in three types of homes: an all-electric home, a mixed-fuel home with partially electrified space heating, and a mixed-fuel home using only gas for space heating. We define these homes as follows:

- All-electric home (Full Electrification): A household that switches all gas equipment to electric equipment. This household uses heat pump technologies for space and water heating, induction electric cooking equipment, and a conventional electric clothes dryer.
- Mixed-fuel home with partially electrified space heating (Partial Electrification): A household that uses a heat pump to provide space heating for most of the year while retaining gas heating equipment as a backup for the coldest days. This household also uses gas for water heating, cooking, and clothes drying year-round. This household still uses electricity for end uses such as lighting, and electronics.
- Mixed-fuel home with gas space heat (No Electrification): A household that still uses gas appliances for space heating, water heating, cooking, and clothes drying. This household uses electricity for end uses such as lighting and electronics.

Synapse developed average gas and electric usage levels for residential customers across the three types of homes. Table 18 and Table 19 below show average annual energy use for each type of household. We developed an average annual gas usage for each end use based on Minnesota-specific data provided by EIA's RECS. For mixed-fuel homes with partially electrified space heat, we assumed that 71 percent of space heating load is served by heat pumps and the remaining 29 percent is served by gas. We then estimated an average annual electricity usage for each end use by converting gas usage to electric usage based on the efficiencies of gas and electric appliances.

Table 18. Average annual gas usage for residential households (therms)

End Use	No Electrification	Partial Electrification	Full Electrification
Space heating	641	186	0
Water heating	181	181	0
Cooking	21	21	0
Drying	20	20	0
Total	**863**	**408**	**0**

Table 19. Average annual electricity consumption for residential households (kWh)

End Use	No Electrification	Partial Electrification	Full Electrification
Space heating[97]	378	4,889	6,732
Water heating	0	0	1,184
Cooking	0	0	286
Drying	0	0	543
Other end uses[98]	3,329	3,329	3,329
Total	3,707	8,218	12,074

We then estimated annual electric and gas bills for each home type, using our projections of gas and electric rates through 2050, as discussed in Chapter 3. In the years leading up to 2050, residential gas rates are expected to increase dramatically as fewer customers are on the system, particularly in the Full Electrification Case. Electricity rates are projected to decrease steadily in real-dollar terms over time in both the Full Electrification and Electrification + Alternative Fuels scenarios, due to two primary factors: (a) electric rates under a business-as-usual scenario based on EIA's Annual Energy Outlook are projected to decline over time, and (b) the downward rate pressure stemming from increased electricity sales due to building electrification projected under each scenario outweighs the upward rate pressure from additional T&D investments to accommodate the demand from building electrification.

97 Includes electricity used by gas furnace fans for homes using gas space heat equipment.

98 This category combines categories from EIA RECS that are not explicitly modeled in the BDC, including refrigerators, clothes washers, TVs and related, and lighting.

Our residential bill analysis estimates the total energy bills for residential customers between 2023 and 2050. Below, we present our preliminary bill results over the next 20 years as well as the full timeframe through 2050. Table 20 and Table 21 show the average annual bill impacts and total bill impacts over the next 20 years and through 2050 by scenario. We find that, on average over the next 20 years, all-electric homes in the Electrification + Alternative Fuels scenario will save an average of $540 per year on energy costs relative to non-electrified homes with gas heat. This is because gas prices are expected to rise as increasing amounts of RNG replaces pipeline gas. In the Full Electrification scenario, average energy bills over the next 20 years for an all-electric home will be roughly $190 lower per year than a non-electrified home with gas heat. Table 22 shows the 20-year average bill breakdown by scenario and end use. The average bill for a fully electrified home is largely similar between both scenarios, whereas the partially and non-electrified homes' bills experience a notable difference between the Electrification + Alternative Fuels and Full Electrification scenarios.

When we expand the timeframe through 2050, all-electric homes will save a substantial amount of money on energy costs relative to non-electrified homes in both the Electrification + Alternative Fuels and Full Electrification scenarios. This is driven by the sharp increases in gas prices in the late 2040's.

Table 20. Average annual and total utility bills over 20 years ($2022)

Energy Bills over 20 Years	Average annual gas bill	Average annual electric bill	Average annual energy bill	Net Present Value 20-year energy bill
Electrification + Alternative Fuels Scenario				
No Electrification	$1,602	$472	$2,074	$28,574
Partial Electrification	$757	$1,046	$1,802	$25,458
Full Electrification	$0	$1,536	$1,536	$22,327
Full Electrification Scenario				
No Electrification	$1,242	$468	$1,710	$24,250
Partial Electrification	$587	$1,037	$1,624	$23,323
Full Electrification	$0	$1,524	$1,524	$22,153

Table 21. Average annual and total utility bills through 2050 ($2022)

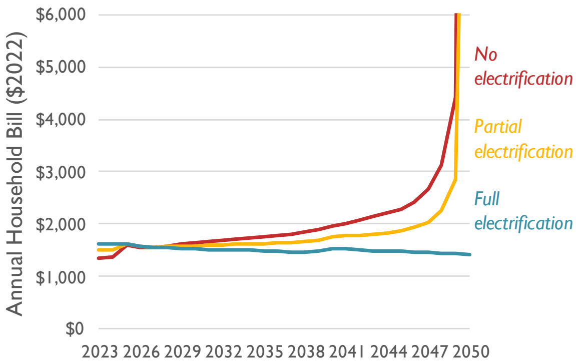
Energy Bills through 2050	Average annual gas bill	Average annual electric bill	Average annual energy bill	Net Present Value of total energy bill
Electrification + Alternative Fuels Scenario				
No Electrification	$2,235	$466	$2,700	$43,840
Partial Electrification	$1,056	$1,032	$2,088	$35,521
Full Electrification	$0	$1,517	$1,517	$27,649
Full Electrification Scenario				
No Electrification	$2,573	$462	$3,035	$45,671
Partial Electrification	$1,216	$1,024	$2,239	$36,270
Full Electrification	$0	$1,504	$1,504	$27,432

Table 22. Average annual utility bills over 20 years by end-use and scenario ($2022)

	Electrification + Alternative Fuels Scenario			Full Electrification Scenario		
End Use	**No Electrification**	**Partial Electrification**	**Full Electrification**	**No Electrification**	**Partial Electrification**	**Full Electrification**
Space heating	$1,239	$967	$856	$970	$885	$849
Water heating	$335	$335	$151	$260	$260	$149
Cooking	$38	$38	$36	$30	$30	$36
Drying	$38	$38	$69	$29	$29	$69
Other end uses	$424	$424	$424	$420	$420	$420
Total	**$2,074**	**$1,802**	**$1,536**	**$1,710**	**$1,624**	**$1,524**

Figure 30 below presents the annual energy bills for the three different types of households under the Electrification + Alternative Fuels and Full Electrification scenarios. Energy bills for all-electric households decline slightly over the analysis period. Energy bills for the partially electrified households and non-electrified households are initially lower than the bills for fully electrified households, and become more expensive towards the mid-to-late-2030's. In the late 2040's, gas bills for any homes retaining gas connections grow exponentially as fewer and fewer homes are expected to bear the cost burden.

Figure 30. Annual total energy bills for residential customers through 2050 (Left: Full Electrification Scenario, Right: Electrification + Alternative Fuels Scenario)



Note: the Y-axis of the Full Electrification Scenario has been truncated at $6,000. The 2050 annual household bill values for the No Electrification and Partial Electrification go up to $31,500 and $15,700 respectively.

Homeowners who install all-electric heating equipment are expected to see bill savings roughly 4–5 years after installation. This is a result of Minnesota's current gas rates being low relative to electricity rates, and expected gas rate increases over time. For homes currently relying on propane or oil, residents are likely to save money on energy on an earlier timescale after switching to heat pump technologies.

6.2 Total Costs

Synapse estimated the total costs for the system as a whole under both modeled scenarios using estimates developed in earlier sections of the report. This total accounts for equipment costs, fuel supply costs, net electric sector costs, gas system costs, as well as environmental externalities.

Upon summing up the aforementioned cost categories, Synapse finds that the Full Electrification case will cost between $13.3 to $14.6 billion dollars less than the Electrification + Alternative Fuels case in net-present-value terms (see Table 23). While Synapse analysis shows that the net electric sector costs (including transmission, distribution, and supply) relative to a business-as-usual scenario are 45 percent higher in the Full Electrification case than the Electrification + Alternative Fuels case, gas system revenue requirements and fuel costs are substantially lower. In fact, gas system costs are 22 to 31 percent higher in the Electrification + Alternative Fuels case,[99] and fuel costs are more than double in the Electrification + Alternative Fuels case relative to the Full Electrification case. Equipment costs in both cases are comparable and within 5 percent of each other. Environmental externalities are $2 to $5 million higher in NPV-terms in the Electrification + Alternative Fuels case due to the increased combustion of fossil fuels over the analysis period.

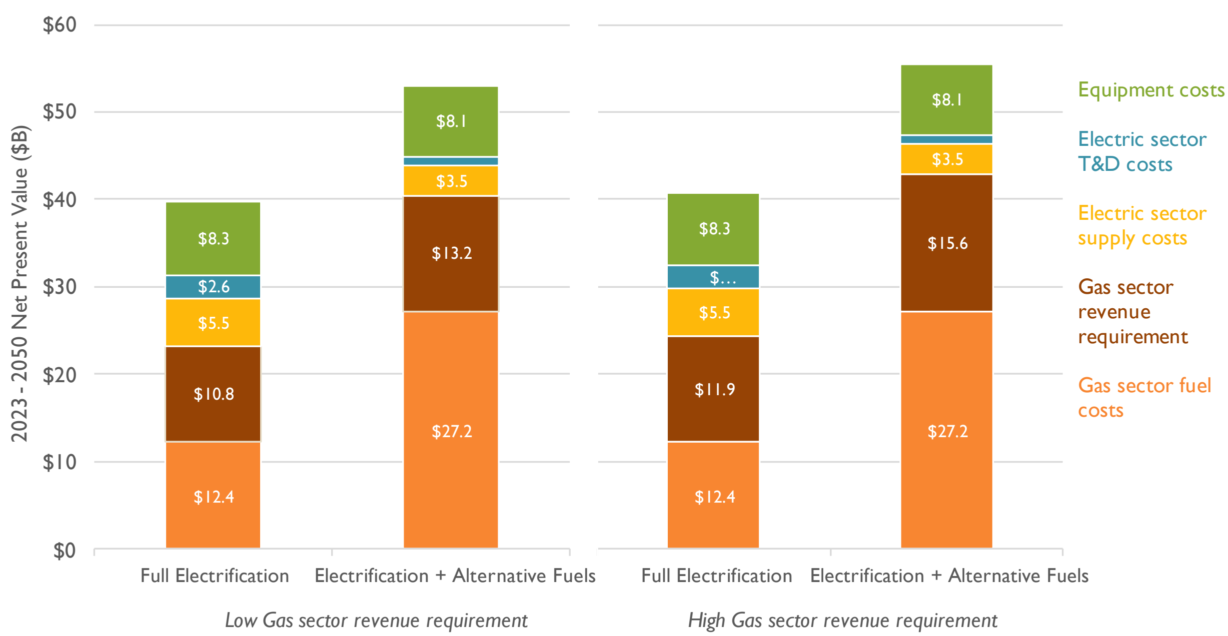
[99] The gas system revenue requirement is presented as a range, as these costs will vary depending on the future outlook of the industrial sector. Synapse's analysis did not include an in-depth look at industrial sector decarbonization.

Table 23. Net present value by cost category and scenario (billions of 2022$)

Cost Group	Cost Category	Full Electrification	Electrification + Alternative Fuels	Delta
Electric Sector	Net T&D Costs	$2.6	$1.0	$1.6
Electric Sector	Net Supply Costs	$5.5	$3.5	$2.1
Gas Sector	Revenue Requirement, High	$11.9	$15.6	-$3.7
Gas Sector	Revenue Requirement, Low	$10.8	$13.2	-$2.3
Gas Sector	Fuel Costs	$12.4	$27.2	-$14.9
Customer	Capital Costs	$8.3	$8.1	$0.2
Societal	Net Environmental Externalities, High		$0.005	$0.005
Societal	Net Environmental Externalities, Low		$0.002	$0.002
Total	**High Estimate**	**$40.8**	**$55.4**	**-$14.6**
Total	**Low Estimate**	**$39.7**	**$53.0**	**-$13.3**

Figure 31 below shows the breakdown of total portfolio costs across both scenarios under a future in which gas sector revenue requirements are lower due to higher cost-sharing by the industrial sector, as well as a future in which gas sector revenue requirements are higher due to less cost-sharing by the industrial sector.

Figure 31. Net present value of total portfolio costs by scenario



Note: Environmental externalities are too small to be visible in this figure and are not shown.

7. SENSITIVITY ANALYSIS

The following section focuses on three strategies that support building decarbonization: GSHPs, demand response actions, and network geothermal systems. The first section presents the impact on energy systems and total resource cost if analysis assumes a higher market share for GSHPs. The second section explores the impact of demand response measures, such as the reduction of space and water heating loads during peak hours, on winter peak loads in the Full Electrification scenario. Finally, we present an overview of network geothermal systems, with an assessment of their advantages and disadvantages.

7.1 High Ground-Source Heat Pump Market Share

GSHPs are a less common type of heat pump in the United States compared to ASHPs. The installation costs of a GSHP are often substantially more expensive than a similarly sized ASHP system because they require installation of the ground loops in addition to the building HVAC equipment. However, total lifecycle costs for GSHPs can sometimes be lower for large-scale applications, due to high-efficiency operation. GSHPs are highly efficient year-round, with the seasonal average COP values ranging from 3 to 5, as ground temperatures are warmer than the outside air in winter and cooler than the air in the summer. We assume a COP of 3.43 for GHSPs in the state for the first year of our analysis based on an in-field study specific to GSHP projects in Minnesota.[100] In comparison, our estimates of COP values for ASHPs range from 2.2 to 3.0 depending on the type of heat pump and building type (residential or commercial).

In our primary scenarios (Full Electrification and Electrification + Alternative Fuels) we assumed a conservative trajectory for GSHP adoption in Minnesota: 5 percent of heat pumps installed will be GSHP, based on the share of ASHPs and GSHPs projected through 2029 as part of the Minnesota Potential Study.[101] To explore the effects of higher efficiencies from GSHPs, we ran a sensitivity analysis focusing on electrification with a greater reliance on GSHPs. We modeled a new scenario that included a higher GSHP market share (25 percent of heat pump sales) and analyzed the impacts of GSHPs on energy consumption, emissions, and cost. This scenario otherwise kept the same assumptions as the Full Electrification case. Likely trade-offs of this scenario include higher upfront consumer equipment costs but lower ongoing fuel costs and lower electric system peak impacts compared to the Full Electrification scenario.

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[100] University of Minnesota, Cold Climate Housing Program. 2016. *Residential Ground Source Heat Pump Study*. Prepared for Minnesota Department of Commerce. Available at: https://mn.gov/commerce-stat/pdfs/card-residential-gound-source-heat-pump-study.pdf.

[101] Center for Energy and Environment (CEE). 2019. *Minnesota Energy Efficiency Potential Study: 2020-2029, Appendix A: Methodology and Data Sources.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources. Available at: https://www.mncee.org/sites/default/files/2021-06/Appendix-A_Methodology-and-Data-Sources_2019-03-27_FINAL.pdf.

Our building sector and gas sector models operate under an aggregate stock turnover and sales framework. We did not explicitly consider emerging GSHP technologies in our modeling, as they are not at commercial scale. Nor did this analysis explicitly model networked geothermal systems. For more discussion on the potential and application of networked geothermal systems, see Section 7.3.

7.1.1.1 Building sector

Figure 32 summarizes the key assumptions of our modeling relating to GSHP space heating end use in buildings. In all scenarios, all-electric whole-building ASHPs are the primary decarbonization strategy for buildings. As shown in Figure 32, in both the Full Electrification case and Electrification + Alternative Fuels case, GSHPs consistently make up a low fraction of residential and commercial space heat equipment sales. All scenarios assume aggressive electrification trajectories. To reach net-zero emissions by 2050, heat pump sales, including GSHPS, must dramatically increase by 2030 in both the commercial and residential sectors compared to current market trends. By 2030, GSHPs account for 22 percent of residential space heating equipment sales in the High GSHP case, with all-electric ASHPs accounting for another 75 percent of total residential space heating equipment sales. The relative share of GSHPs decreases in the late 2040s when the number of early replacement ASHPs increases to replace existing heating systems to meet the emissions reduction targets.

Figure 32. GSHP market shares by scenario

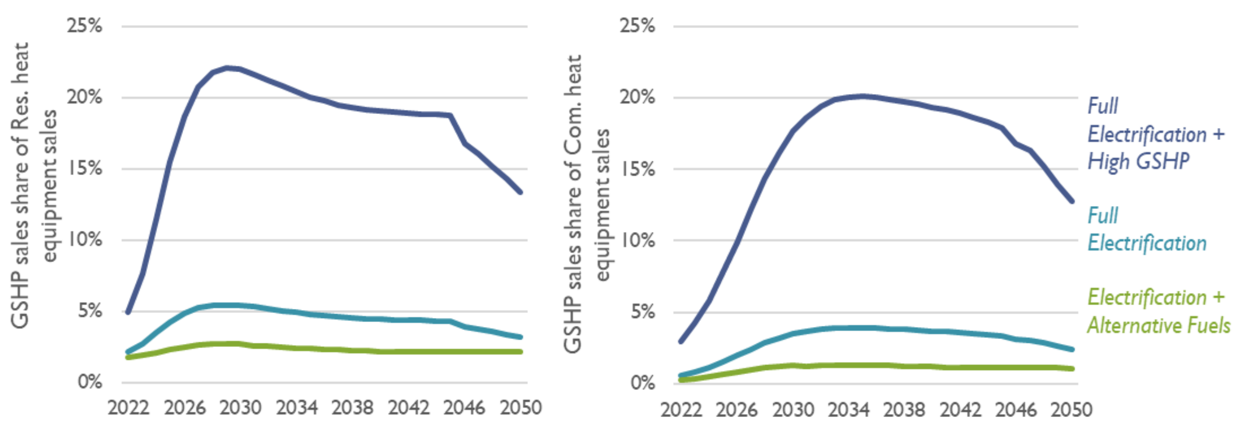


Figure 33 shows the trajectories of space heating stock for residential buildings across the three scenarios. Like the Full Electrification case, the GSHP scenario assumes that in the last five years leading up to 2050, some fossil fuel equipment will be replaced with heat pumps before the end of its useful life. In the High GSHP case, GSHPs account for 22 percent of installed space heating systems in 2050, four and eight times higher than in the Full Electrification case and Electrification + Alternative Fuels case, respectively. The commercial sector GSHP case follows the same trends as the residential sector.

Figure 33. Residential space heating stock for all three modeled scenarios

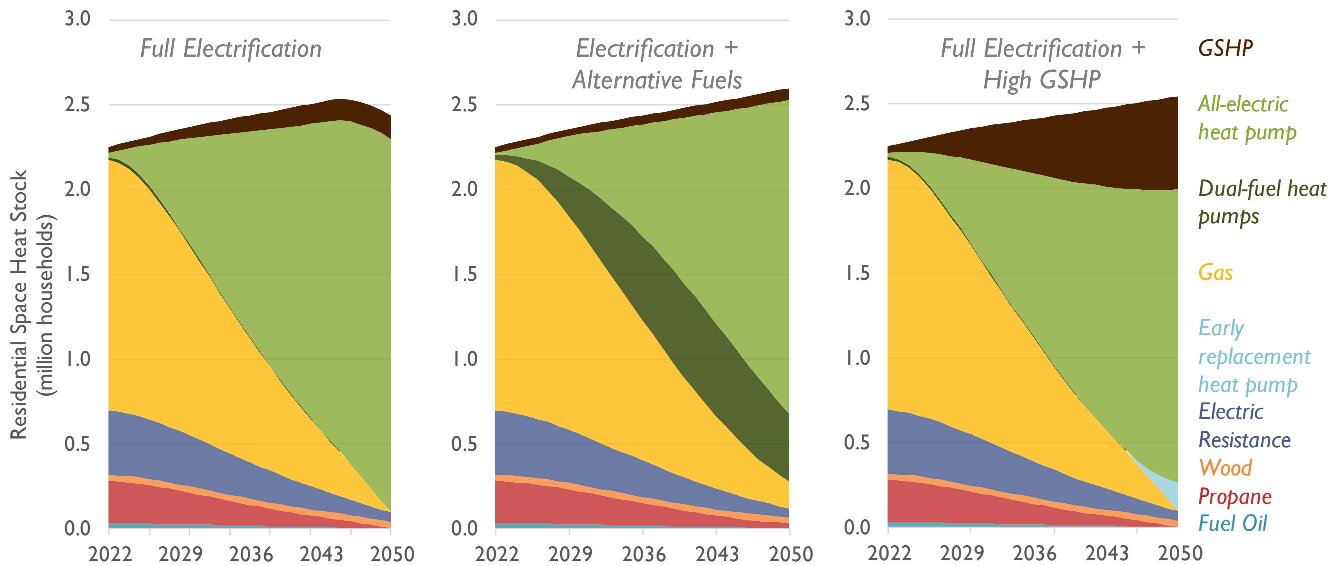
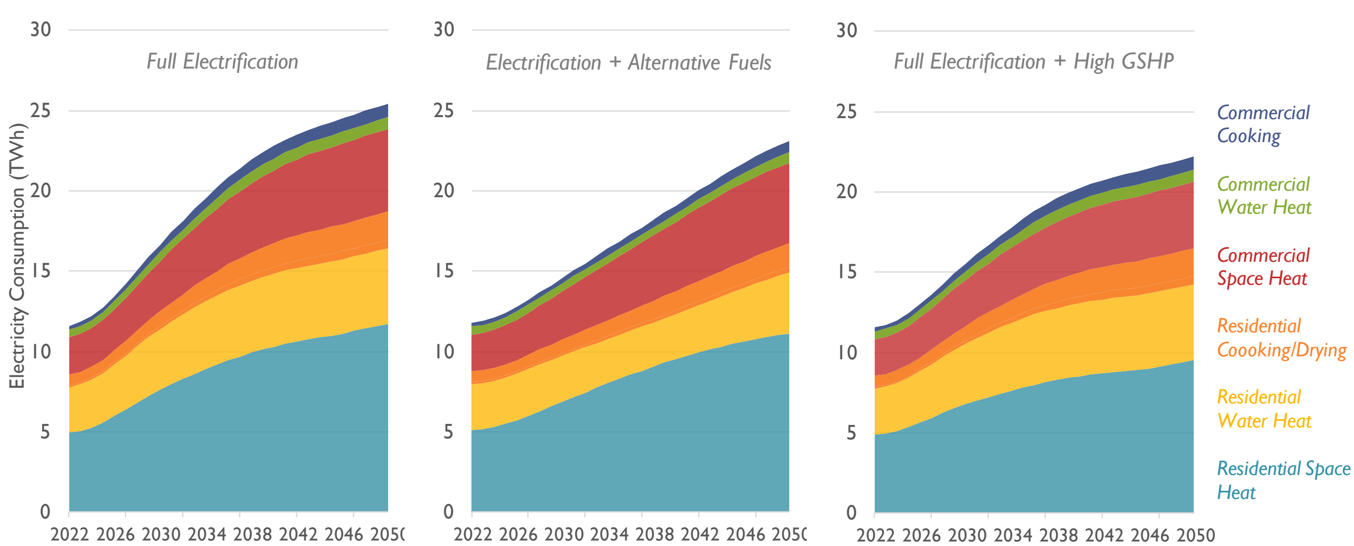


Figure 34 shows the projected annual electricity consumption of the residential and commercial sectors for all three modeled scenarios. All three are projected to roughly double annual electricity consumption. The High GSHP case is projected to require roughly 12 percent less electricity in 2050 than the Full Electrification case. Note that these estimates are conservative in that they account for the effect of higher efficiency GSHPs over ccASHPs, but not the effect of industrial or commercial load-sharing, such as in network geothermal systems. For more discussion of networked geothermal systems, see Section 7.3.

Figure 34. Annual electricity consumption by sector and end-use for all three modeled scenarios



7.1.2 Energy Systems Impacts

Based on the results of the building decarbonization analysis, Synapse analyzed the gas and electric utility financial and customer impacts of the High GSHP scenario compared to the Full Electrification and Electrification + Alternative Fuels scenarios. We assumed that the High GSHP scenario would keep the same assumptions as the Full Electrification scenario. Thus, the impacts on gas sales are almost the same between these two scenarios. We estimate that fossil gas sales decrease by more than 99 percent under both scenarios by 2050. For both scenarios, we assumed that the gas utilities would pursue clustered electrification and would update their depreciation rates, to reflect the utilities' planning for the strategic decommissioning of the gas system, alongside full electrification.

As shown in Figure 35, the gas revenue requirement for the residential and commercial sectors in the High GSHP scenario follows a nearly identical trajectory to the Full Electrification case, due to the accelerated depreciation under those scenarios compared to the Electrification + Alternative Fuels scenario.

Figure 35. Residential and commercial gas revenue requirement

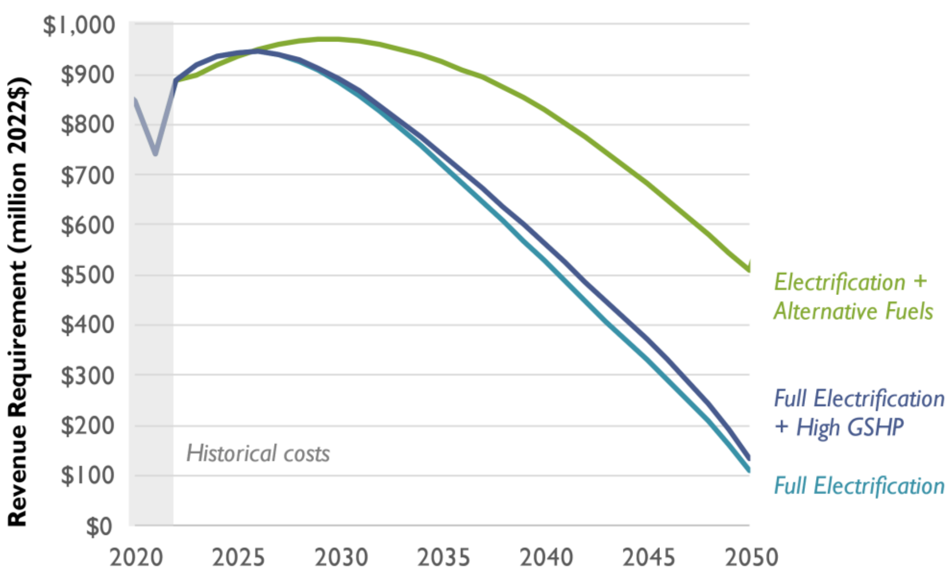


Figure 36 similarly shows that residential gas rates under the High GSHP are nearly the same as the Full Electrification scenario. By the early 2040s, gas rates in the Full Electrification and High GSHP scenarios have doubled, while rates in the Electrification + Alternative Fuels scenario have tripled, driven by the high costs of alternative fuels and rising delivery rates. By the late 2040s, as most customers have departed the gas system, rates begin to spike because the costs of the delivery system must be split over fewer and fewer dekatherms of gas delivered.[102] Gas rates under the High GSHP case are 10 percent higher in 2045 compared to the Full Electrification case.

Figure 36. Residential gas revenue per dekatherm by scenario, including the Full Electrification + High GSHP case

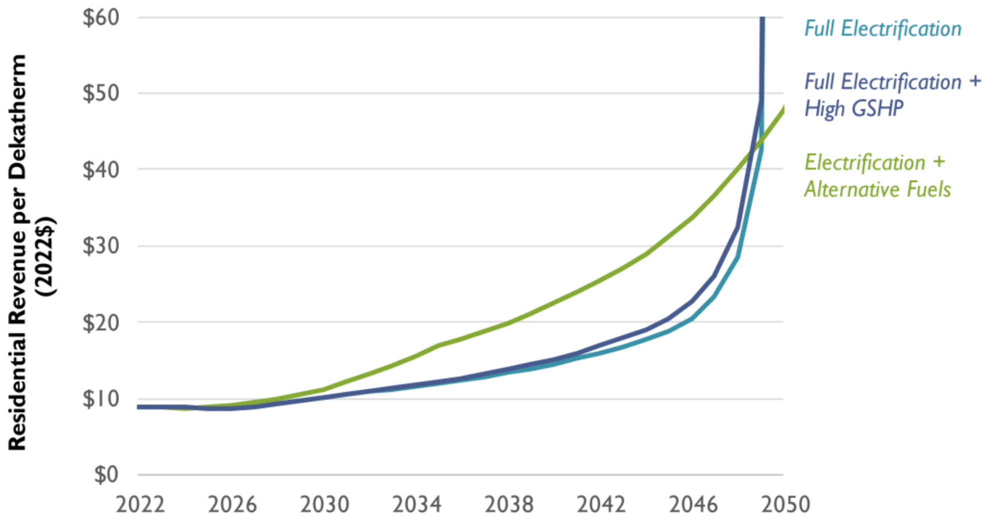


Figure 37 shows our projection of winter electric system peak load impacts accounting for extreme weather effects for each scenario including the Full Electrification + High GSHP case (also called "High GSHP case"). The projected peak load impacts for the High GSHP are roughly 6 to 10 percent lower through 2050 than the Full Electrification case. On absolute terms, the winter peak load savings for the High GSHP case relative to the Full Electrification case increase from 1 GW in 2030 to as much as 3 GW in 2050. The peak load impacts for the High GSHP case are still significantly high in early years in comparison to the impacts for the Electrification + Alternative Fuels case but are expected to reach approximately the same peak load level in 2050.

[102] Due to the rapid decrease in the number of customers on the gas system, rates in 2050 for the Full Electrification and Full Electrification + GSHP cases are beyond the scale of Figure 36.

Figure 37. Winter peak load impacts for all end uses by scenario, including the Full Electrification + High GSHP case

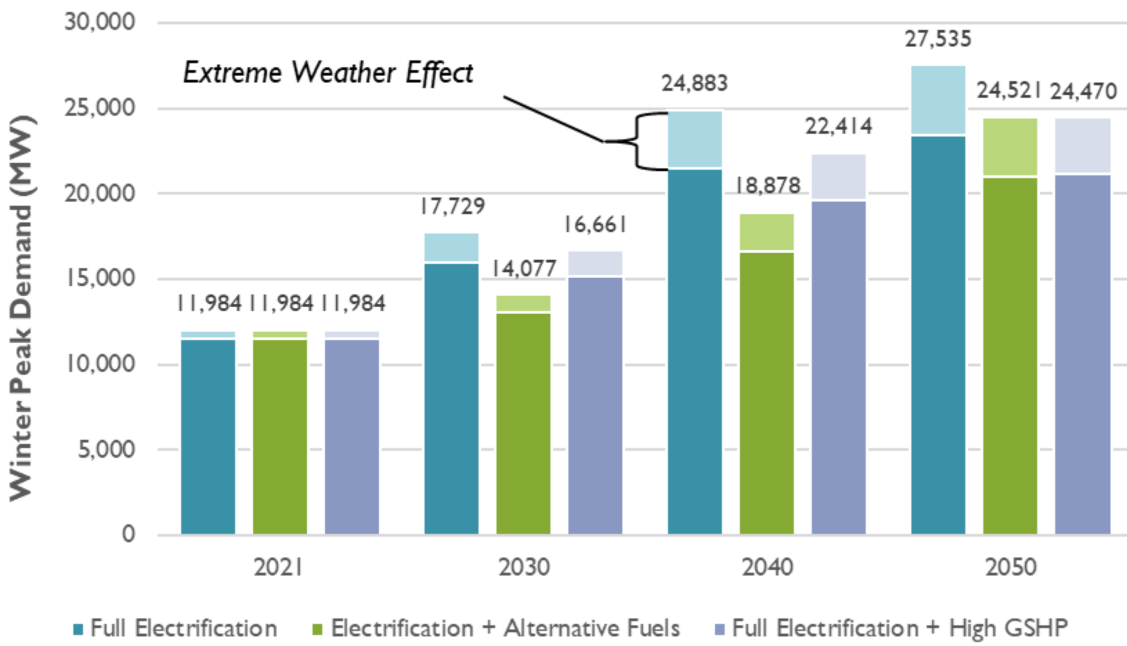


Figure 38 shows a comparison of net annual T&D investments across all three scenarios. Unlike the impacts on the gas system impacts, the High GSHP case is expected to have substantially lower T&D costs than the Full Electrification case. In comparison to the Full Electrification case, the High GSHP case is expected to cost 20 percent to 30 percent less on an annual basis. In comparison to the Electrification + Alternative Fuels case, the High GSHP case still costs more for most of the time, with the annual costs being higher by about 200 percent or $100 million. However, the cost gap is expected to start narrowing around 2038 and disappear by 2050. Overall, the High GSHP case cost approximately $1.9 billion (in present value or PV) cumulatively through 2050 as shown in Table 24 below. This is approximately 27 percent less than the Full Electrification case and 90 percent more than the Electrification + Alternative Fuels case.

Figure 38. Projected net annual T&D investments by scenario, including the Full Electrification + High GSHP case

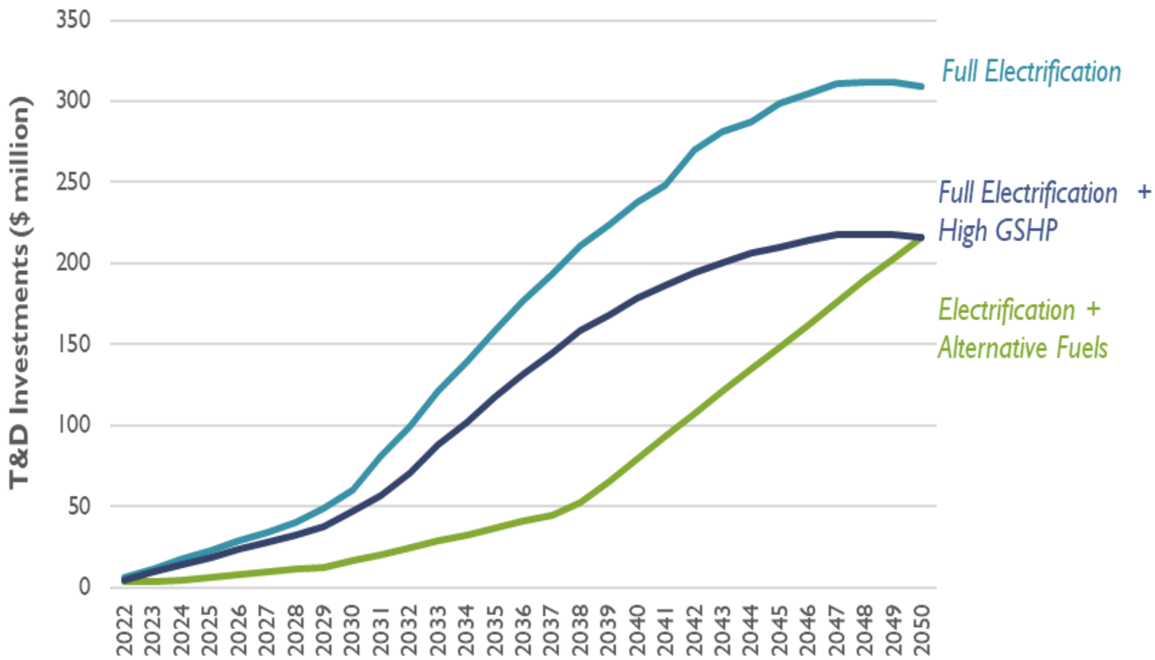


Table 24. Total present value of net T&D investments by scenario and sector, including the Full Electrification + High GSHP case ($ million, PV)

	Residential	Commercial	Total
Full Electrification	2,062	563	2,624
Electrification + Alternative Fuels	905	141	1,034
Full Electrification + High GSHP	1,619	309	1,929

Figure 39 presents a summary of average electricity delivery rate projections by scenario including the rate projection for the High GSHP case. Our analysis found that the rate projection for the High GSHP case is nearly identical to the rate projection for the Full Electrification case.

Figure 39. Projected residential electricity delivery rates by scenario, including the Full Electrification + High GSHP case

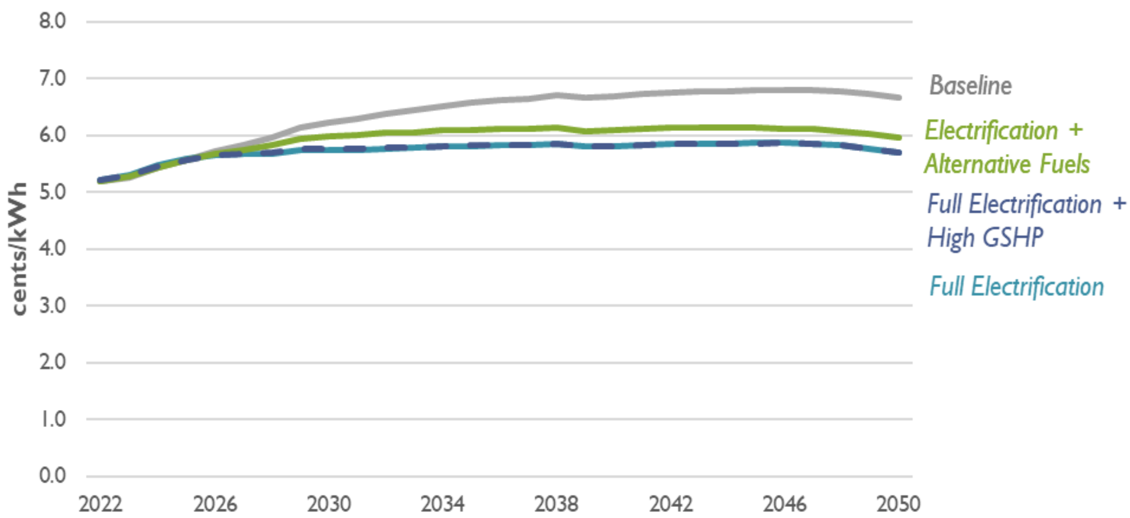


Table 25 presents a detailed comparison of levelized electricity delivery rates by scenario including the High GSHP case.[103] As shown in this table, the net incremental T&D cost for the High GSHP case (0.28 cents/kWh) is lower than for the Full Electrification case (0.35 cents/kWh). However, the impact of the increased revenues due to electrification is greater for the Full Electrification case (-1.12 cents/kWh) than the High GSHP case (-1.05 cents/kWh). The net impacts of these two factors make the average delivery rates for these two cases almost the same.

Table 25. Comparison of levelized electricity delivery rates by scenario (cents/kWh)

	Baseline	Increased revenue due to electrification	Net incremental T&D costs due to electrification	Total delivery rates	Rate change (% of baseline)
Full Electrification	6.66	-1.12	0.35	5.90	-11.55%
Electrification + Alternative Fuels	6.66	-0.74	0.16	6.08	-8.71%
Full Electrification + High GSHP	6.66	-1.05	0.28	5.90	-11.49%

[103] We levelized the rate projections using a 3.3 percent real discount rate.

7.1.3 Costs

We estimated current total per-unit installed costs for electric and gas end-use equipment for residential and commercial buildings.[104] In this analysis we assume a GSHP equipment cost of $31,447 for residential buildings, and $26,094 per thousand square feet for commercial buildings. These estimates are based on a 2017 NYSERDA study of GSHP costs and incremental costs from the Minnesota Technical Reference Manual.[105,106] GSHP equipment costs are twice as high as all-electric ccASHPs. These total upfront installed costs include equipment and labor costs but exclude ongoing operation and maintenance costs. See Chapter 3 for further details on equipment cost projections.

As shown in Table 26, total upfront consumer costs increase under the High GSHP scenario.[107] The total equipment costs for the Full Electrification + High GSHP case are 3 percent higher than the Full Electrification case and 5 percent higher than the Electrification + Alternative Fuels case. This is primarily due to increased customer capital costs for residential space heating, resulting from higher GSHP adoption.

Table 26. Present value capital costs under each decarbonization scenario (billions of 2022$)

Sector	Full Electrification	Electrification + Alternative Fuels	Full Electrification + High GSHP
Residential equipment costs	$3.70	$3.54	$3.87
Commercial equipment costs	$4.06	$4.09	$4.11
Residential and commercial total equipment cost	**$7.76**	**$7.62**	**$7.98**

7.2 Demand Response

As discussed in Chapter 5, our analysis of electric peak load impacts from building electrification for the Full Electrification scenario and for the Electrification + Alternative Fuels scenario does not include any impacts of demand response measures such as reducing space and water heating loads during peak hours. This is one of the few important factors that we discussed in Chapter 4 that make our analysis of peak load impacts conservative. As a sensitivity assessment, this section explores the potential impacts of demand response on the winter peak load impacts for the Full Electrification scenario.

[104] While the focus of this section is on the comparison of gas and electric equipment costs, this analysis did include the costs of electric resistance, propane, and fuel oil systems.

[105] NYSERDA. 2017. *Renewable Heating and Cooling Policy Framework*. Available at: https://www.nyserda.ny.gov/About/Publications/Research-and-Technical-Reports/Clean-Heating-and-Cooling-Reports.

[106] MN Department of Commerce. 2023. *Minnesota Technical Reference Manual for Energy Conservation Improvement Programs, Version 4.0*. https://mn.gov/commerce-stat/trm/releases/4.0.pdf.

[107] This table does not include panel upgrade costs, because the High GSHP panel costs are the same as the Full Electrification panel upgrade costs.

While demand response programs in many Minnesota utilities and many other parts of the country have been focusing on summer peak loads, various types of demand response measures can be implemented during the winter to reduce winter peak loads.[108] Among others, two major winter demand response measures are smart thermostats for space heating and direct load controls of storage water heaters (e.g., standard HPWHs). Great River Energy, a transmission and generation cooperative and the second largest electric utility in Minnesota, also uses electric thermal storage to control space heating demand in addition to water heater demand response measures. In fact, Great River Energy is a leading utility on winter demand response programs in the country and has been implementing its demand response programs for many years. As of 2021, the utility had enrolled over 112,000 participants in its water heater programs—approximately 17.5 percent of all customers' water heaters with the total potential peak savings capacity of 52 MW to over 100 MW (or approximately 2.5 to 5 percent of the total winter peak load).[109]

Utilities can also implement other types of demand response measures and programs to reduce winter peaks. A few important, emerging demand response measures are managed EV charging and electric batteries. A growing number of utilities are implementing managed EV charging programs.[110,111] In addition, a conventional demand response measure such as the use of a building automation system can be used to control various commercial building end uses (e.g., lighting, ventilation, and other equipment) to reduce winter peak loads. Lastly, rate designs and bill credit-related programs such as time-of-use rates, critical peak pricing, interruptible tariffs, and peak time rebates can be used to encourage customers to reduce peak loads through various demand response technologies mentioned above.

As a sensitivity assessment to our core analysis as discussed in Chapter 4, we conducted a high-level analysis of the potential impacts of demand response for the Full Electrification scenario, with a focus on space and water heating end uses in 2050. We estimated the overall peak load savings based on our estimate of per-participant kW savings and program participation rates for 2050.

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[108] For example, Xcel Energy Minnesota's 2024-2026 ECO Triennial Plan focuses on summer peak demand response, while it introduced, for the first time, smart water heaters that can be controlled to reduce load during morning peak. See the "Demand Response Segment" section of this plan at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/23-92%20-%202024-2026%20MN%20Triennial%20Plan%20062923.pdf.

[109] Blumenstock et al. 2021. *Great River Energy: Water Heater Potential and Application*. Pages 8, 9 and 12. Available at: https://conservancy.umn.edu/bitstream/handle/11299/221962/Great%20River%20 Energy%20UMN%20Capstone%20Final%20Report.pdf?sequence=1&isAllowed=y.

[110] Smart Electric Power Alliance. 2021. *The State of Managed Charging in 2021*. Available at: https://sepapower.org/resource/the-state-of-managed-charging-in-2021/.

[111] While the impact of controlling and reducing charging loads for EVs is likely to be smaller in the winter than in the summer, EV batteries could also be used to reduce winter peak loads if EVs are connected to homes and buildings (through a vehicle-to-home (V2H) application) and not used in the morning.

We developed per-participant, winter peak load reductions in terms of percentage of peak loads by end use based on a literature review of demand response potential studies. Table 27 provides a summary of winter peak savings factors by end use and sector.

Table 27. Demand response winter peak savings factors

End-use	% Savings	Sources and notes
Residential End Use		
Space heating	25%	Based on peak impacts ranging from 1.2 to 2.9 kW from the following sources: Cadmus (2018) Demand Response Potential in Bonneville Power Administration's Public Utility Service Area; Center for Energy and Environment (2019) Minnesota Energy Efficiency Potential Study: 2020–2029. Appendix E; Navigant (2011) 2011 EM&V Report for the Puget Sound Energy Residential Demand Response Pilot Program.
Domestic hot water	60%	Assumes half of water heaters in demand response programs are turned off and the remaining water heaters are cycled. Savings estimates are based on Cadmus (2018) DR Potential in BPA; Brattle (2016) The Hidden Battery, Opportunities in Electric Water Heating.
Commercial End Use		
Space heating	25%	Ranges from 20 to 30% based on Cadmus (2018) Demand Response Potential in Bonneville Power Administration's Public Utility Service Area; Brattle (2016) PGE DR Market Research 2016–2035; Siemens (2017) C&I Technical Test Final Report
Domestic hot water	60%	Synapse assumption based on residential DHW potential

We developed our forecast of program participation rates primarily based a 2021 study by U.S. Department of Energy (DOE) titled *A National Roadmap for Grid-Interactive Efficient Buildings*. This study developed cumulative participation ranging from 10 to 55 percent over a 10-year timeframe (2021–2030) for three cases (Low, Mid, and High) based on a detailed review of numerous demand response potential studies. Because our sensitivity analysis focuses on 2050, which is more than 25 years from today, we made some upward adjustments to DOE's participation rates by increasing the cumulative rates by just 25 percent. Table 28 shows the resulting cumulative participation rates assumed for our analysis.

Table 28. Demand response cumulative participation rates in 2050

End use	Low	Mid	High
Res Space heating	25%	38%	69%
Res Water heating	25%	38%	69%
Com Space heating	13%	31%	50%
Com Water heating	25%	38%	69%

Finally, by applying the per-participant savings factor to the cumulative participation rates in 2050, we estimated the total peak load reductions from demand response for space and water heating (excluding any other demand response measures such as EV managed charging, electric batteries, and other commercial end uses such as lighting and ventilation) as shown in Table 29 below. The total winter peak savings range from 1 GW to 3 GW, which represent 6 to 17 percent of the total end-use load or 4 percent to 11 percent of the total system load. The largest peak savings come from residential space heating demand response, which accounts for about 64 percent to 72 percent of the total peak savings depending on the scenario.

Table 29. Potential winter peak load reductions from demand response in 2050 for the Full Electrification case (in MW, unless otherwise noted)

End use	Low	Mid	High
Res Space heating	740	1,110	2,035
Res Water heating	94	141	258
Com Space heating	186	466	745
Com Water heating	13	19	36
Total	**1,033**	**1,736**	**3,074**
Total (% of end use load)	**6%**	**9%**	**17%**
Total (% of total load)	**4%**	**6%**	**11%**

Our demand response analysis focuses just on 2050, but we could estimate a rough total T&D cost impact through 2050 by applying these total percentage peak reductions to the total cumulative T&D costs. We estimated that the Full Electrification case results in approximately $2,600 million (PV) through 2050 (as shown in Table 8). This implies that the total potential T&D cost savings through demand response on space and water heating end uses could range from approximately 100 million to 290 million based on the results of our demand response analysis. It is important to note that these cost estimates do not include the costs of demand response measures, which is outside the scope of this sensitivity analysis.

7.3 Network Geothermal

District energy systems, in some cases known as district thermal networks, are characterized by a central plant producing steam or hot water that flows through a network of insulated pipes to provide space heating, hot water, and other end uses to buildings connected to the system.[112]

Networked geothermal systems are a form of district energy systems[113] that combine GSHPs in individual buildings with district energy to create highly efficient, neighborhood-scale heating and cooling systems. As one of the most energy efficient forms of building electrification, network geothermal systems can contribute to decarbonization efforts. They also provide a potential avenue for gas utilities to re-use existing assets such as rights-of-way as the gas system winds down, and to preserve pipeline jobs. Challenges with network geothermal include high costs and uncertainty about future performance due to the technology being in an early stage of development.

7.3.1 Technology Overview

Network geothermal systems combine two technologies: GSHPs and district energy. In a GSHP system, a working fluid exchanges heat with the ground while circulating through a series of vertical geothermal boreholes. It then flows through a GSHP unit, usually located within a single building. The heat pump employs a thermodynamic cycle to either extract heat from the working fluid (to heat the building) or reject heat into the fluid (to cool the building). Because the ground stays at a constant temperature year-round, GSHPs have consistently high thermal efficiencies throughout the year, even when the air temperature is very low.

A network geothermal system extracts thermal energy from the ground through a shared borefield and one ambient temperature loop and heats and cools multiple buildings through GSHPs installed in multiple, individual buildings.[114] More specifically, individual GSHPs within each building extract or reject heat into the loop for heating or cooling the building, depending on the thermal needs of the building. This allows a single loop to provide both heating and cooling, and it may allow for load-sharing between buildings that have simultaneous heating and cooling load, further increasing system efficiency.

Few network geothermal systems utilizing a single ambient loop currently exist,[115] but several states have directed their gas utilities to pilot them, including Massachusetts and New York. In Massachusetts,

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[112] Office of Energy Efficiency & Renewable Energy of the US Department of Energy. N.D. *District Energy Systems Overview.* Available at https://www.energy.gov/eere/amo/articles/combined-heat-and-power-technology-fact-sheet-series-district-energy

[113] Traditional district heating systems, with a central plant, can also incorporate GHSPs and HPs.

[114] Buro Happold Engineering. 2019. *Geothermal Networks 2019 Feasibility Study.* Prepared for HEET. Available at: https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/656f8ad67bbc7df081e3fe17_Buro-Happold-Geothermal-Network-Feasibility-Study.pdf.

[115] Three examples are Colorado Mesa University, West Union in Iowa, and Whisper Valley in Texas. For more information, see: Oh, H and Beckers, K. 2023. *Cost and Performance Analysis for Five Existing Geothermal Heat*

Eversource's pilot in Framingham is nearly complete,[116] and National Grid recently began constructing its pilot in Lowell.[117] In New York, planning is underway for an additional 13 pilot projects.[118]

7.3.2 Advantages and Challenges of Network Geothermal Systems

Network geothermal systems have different strengths and weaknesses compared to ASHPs, so as it becomes clear that electrification will be the primary strategy for decarbonizing buildings, it is worth considering the types of situations to which each technology is best-suited.

Higher energy efficiency versus ASHPs: Network geothermal systems are advantageous because of their high energy efficiencies. In addition to the efficiency benefits of using the ground as a heat sink and source, network geothermal systems that rely on one ambient-temperature loop may allow for load-sharing between buildings that have simultaneous heating and cooling loads.[119] For example, a data center with year-round cooling needs may reject heat into the shared loop even in winter. Neighboring homes that are connected to the loop can use this waste energy for heating. While theoretically promising, the extent to which this effect will increase the efficiency of network geothermal systems in practice remains unclear. A recent study of five existing network geothermal systems found that the systems had an average COP of 4.7 but did not detect a significant difference in performance between the two types of systems (i.e., those with separate hot and cold loops and those with ambient-temperature loops).[120] A COP of 4.7 is substantively higher than typical ASHP efficiency and somewhat higher than individual GSHP performance.[121] As pilot projects begin to come online, better data on the magnitude of efficiency gains from load-sharing in network geothermal systems will become available.

Pump-Based District Energy systems in the United States. National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy23osti/86678.pdf.

[116] Eversource. 2023. "Geothermal Pilot Project in Framingham." Available at: https://www.eversource.com/content/residential/about/transmission-distribution/projects/massachusetts-projects/geothermal-pilot-project.

[117] National Grid. 2023. "National Grid Breaks Ground on Geothermal Borehole on UMass Lowell Campus." Available at: https://www.nationalgridus.com/News/2023/04/National-Grid-Breaks-Ground-on-Geothermal-Borehole-on-UMass-Lowell-Campus/.

[118] St. John, J. 2024. "New York will replace gas pipelines to pump clean heat into buildings." *Canary Media,* January 16. Available at: https://www.canarymedia.com/articles/carbon-free-buildings/new-york-will-repurpose-gas-pipelines-to-pump-clean-heat-into-buildings.

[119] Buro Happold Engineering. 2019. *Geothermal Networks 2019 Feasibility Study.* Prepared for HEET. Available at: https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/656f8ad67bbc7df081e3fe17_Buro-Happold-Geothermal-Network-Feasibility-Study.pdf.

[120] Oh, H. and Beckers, K. 2023. *Cost and Performance Analysis for Five Existing Geothermal Heat Pump-Based District Energy systems in the United States.* National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy23osti/86678.pdf.

[121] The average annual COPs of ASHPs and GSHPs vary by climate zone. In Minnesota, ASHP COPs currently range from 2.1 to 3, while GSHP COPs are typically about 3.4 (Appendix A).

Reduced peak impacts on the electric grid: Because the ground temperature is constant year-round, network geothermal systems' efficiency remains high even when the outside air temperature is extremely hot or cold. In contrast, ASHPs may rely on inefficient electric resistance backup when temperatures drop, leading to high peaks in electricity consumption. As more homes electrify, increases in peak load could necessitate expensive grid upgrades. Network geothermal systems also use electricity from the grid, but the peak load impacts from network geothermal systems are expected to substantially lower than ASHPs and so could mitigate the need for grid upgrades. However, the performance of ccASHPs has also increased rapidly in recent years,[122] ameliorating concerns about winter peak impacts and reducing the relative benefit of network geothermal systems compared to ASHPs.

Higher capital cost: One of the main disadvantages of network geothermal systems is their high capital costs. Drilling boreholes and installing the shared underground loop are significant additional costs on top of in-building heat pump installation. For example, Eversource's pilot in Framingham, MA has an estimated construction budget of $10.2 million (including a $5 million investment tax credit), equivalent to approximately $27,000 per ton of capacity.[123] In comparison, the cost per ton of ASHPs in Massachusetts is approximately $7,000.[124] Pilots will likely have particularly high costs as utilities test new system designs, but the magnitude of cost savings that will be available in the future is unknown.

Network geothermal systems economics are especially challenging because these systems are best-suited to high-density neighborhoods, where the length of trenching for the shared loop is minimal and the potential for load-sharing is maximized. Unfortunately, dense urban areas also tend to have very high construction costs, especially for digging boreholes and trenches.

Network geothermal systems do offer operational savings relative to ASHPs that partially make up for their high installation costs. It remains to be seen whether drilling costs will fall enough for network geothermal systems to be cost-effective relative to ASHPs, even in neighborhoods that are better suited to them.

Early-stage technological development: Network geothermal systems with one ambient temperature loop theoretically offer the largest efficiency benefits, but these systems are still in an early stage of technological development, and their future cost and performance is uncertain. For example, the extent of efficiency gains from load-sharing and the need for backup loop heating (e.g., in the case of a borefield outage) are currently unclear.

Equity and gas utility adaptation: Installing and maintaining network geothermal systems requires many of the same skills and equipment as installing and maintaining gas pipelines. Adoption of district

[122] Gibb, D, Rosenow, J, Lowes, R, and Hewitt, N. 2023. "Coming in from the cold: Heat pump efficiency at low temperatures." *Joule 7,* 1-4. https://doi.org/10.1016/j.joule.2023.08.005.

[123] Eversource. 2023. "DPU 21-53 – Budget Update (RTF 10-31-23).xlsx" Massachusetts DPU Docket 21-53.

[124] Massachusetts Clean Energy Center. 2021. "Whole-home ASHP projects database." Available at: https://www.masscec.com/resources/installer-resources-air-source-heat-pumps.

thermal networks provides a potential future for gas utilities, which could transition their businesses to providing thermal energy rather than gas. Utilities could re-use existing assets, such as rights of way, to install network geothermal systems. Deployment of network geothermal systems could also safeguard pipeline jobs that would otherwise be at risk and could provide this skilled workforce with a path forward.

8. ENVIRONMENTAL IMPACT

This section contains the results of a literature review and internal analysis on environmental externalities associated with continued reliance on the gas system. It first provides an overview of the health impacts related to indoor and outdoor air pollution from burning of pipeline natural gas, describing specific impacts on outdoor air quality. We then dive into our analysis of health benefits and their values calculated using the U.S. Environmental Protection Agency's (EPA) CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). Finally, this section further discusses indoor air quality issues stemming from pipeline gas and the role of equity.

Assessing the impacts of building decarbonization also reveals the considerable benefits associated with the reduction of air pollution, both indoors and outdoors, and the potential to reduce the environmental externalities from gas consumption. Across the state of Minnesota and broader United States, studies have shown that burning pipeline gas in homes for gas appliances produces a range of pollutants including nitrogen oxides (NO_X), carbon monoxide (CO), methane (CH_4), nitrous oxide (N_2O), fine particulate matter ($PM_{2.5}$), and formaldehyde.[125] Recent studies have found that these pollutant emissions from indoor gas appliances, especially NO_X emissions, cause negative health impacts such as increased respiratory symptoms, asthma attacks, and hospital admissions for people who have asthma.[126] In the United States, key contributing sources of these combustion byproducts include gas stoves, smoking, and natural gas combustion used for space and water heating.[127] In Minnesota, 1.5 million households rely on gas for cooking, the end use with the largest impact on indoor air pollution. Additionally, 1.9 million households use natural gas for space heating, 1.3 million for water heating, and

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[125] U.S. Environmental Protection Agency. 2019. "The Inside Story: A Guide to Indoor Air Quality" Accessed at: https://www.epa.gov/indoor-air-quality-iaq/inside-story-guide-indoor-air-quality; Zhu, Y., Connoly, R., Lin, Y., Mathew, T., Wang, Z. 2020. "Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California" UCLA Fielding School of Public Health Department of Environmental Services. Accessed at: https://coeh.ph.ucla.edu/2020/04/29/study-gas-powered-appliances-may-be-hazardous-for-your-health/.

[126] See, for example, Seals, B., Krasner, A. 2020. *Health Effects from Gas Stove Pollution*. Rocky Mountain Institute, Physicians for Social Responsibility, Mothers Out Front, and Sierra Club. Available at: https://rmi.org/insight/gas-stoves-pollution-health/.

[127] Adamkiewicz, G. et al. 2011. "Moving Environmental Justice Indoors: Understanding Structural Influences on Residential Exposure Patterns in Low-Income Communities." *American Journal of Public Health* 101 (1). https://ajph.aphapublications.org/doi/full/10.2105/AJPH.2011.300119.

0.7 million for drying.[128] This substantial number of households burning pipeline gas every day shows that Minnesota has an opportunity to reduce environmental externalities through decarbonization. Commercial buildings can benefit as well. Restaurants in particular could realize these benefits by electrifying cooking, given the higher BTU rating (i.e., size) of commercial stoves.

The State of Minnesota recognizes these environmental externalities and their social costs. The state's legislature requires the Public Utility Commission (PUC) to quantify and establish a range of environmental costs associated with the different methods of electricity generation that utilities must consider when selecting resource options in PUC proceedings.[129] In 2018, the PUC issued a decision updating its accepted environmental cost values for criteria pollutants. The decision identified a range of values for each pollutant considered: \$3,437 to \$25,137 per ton of $PM_{2.5}$ emitted, \$1,985 to \$7,893 for NO_X, and \$3,427 to \$14,382 for SO_2 (in 2014 dollars per ton).[130] Updating and increasing the accepted values for these environmental costs was important to ensure that these values are appropriately used for energy-related decision-making in Minnesota.

Air pollution from the different pollutants discussed can cause a wide range of negative health issues such as respiratory irritation and illnesses; cardiovascular disease; fatigue; and damage to the kidneys, liver, and central nervous system.[131] Some health effects are more immediately noticeable than others, and some impact certain demographics disproportionately. For example, children are more likely to have asthma symptoms in homes with a gas stove than an electric one.[132] Meanwhile, older adults face a serious risk of cardiovascular and respiratory health impacts from long-term exposure to combustion-related air pollution, including risk of pneumonia, atrial fibrillation, stroke, and heart attack.[133]

In Minnesota, air pollution from burning fuels in buildings led to an estimated 865 early deaths and \$9.69 billion in health impact costs in 2017. Of the total, NO_X and volatile organic compounds (VOCs)—

128 Synapse calculated these numbers based on ACS data, RECS, and CBECs data, and then adjusted them based on responses from the Minnesota potential study.

129 *Order Updating Environmental Cost Values*, Docket No. E-999/CI-14-643 Minnesota Public Utilities Commission (January 3, 2018).

130 *Ibid*.

131 Tran, V, Park, D, and Lee, Y-C. 2020. "Indoor Air Pollution, Related Human Diseases, and Recent Trends in the Control and Improvement of Indoor Air Quality." *Int J Environ Res Public Health*, 17(8): 2927. https://doi.org/10.3390/ijerph17082927.

132 Gruenwald, T., Seals, B.A., Knibbs L.D., Hosgood, H.D. 3rd. *Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States*. Int J Environ Res Public Health. 2022 Dec 21; 20 (1): 75.

133 Minkara A., Larson, A., Gottleib, B. 2023. *The Outdoor Air Pollution is Coming from Inside the House: National Building Pollution Report.* Available at: https://www.sierraclub.org/sites/default/files/2023-09/AppliancePollution_Report_FINAL.pdf; Tan, Y. A., Jung, B. 2021 *Decarbonizing Homes: Improving Health in Low-Income Communities through Beneficial Electrification*. Rocky Mountain Institute. Available at: http://www.rmi.org/insight/decarbonizing-homes.

two important pollutants associated with burning gas—cost the state an estimated $585 million and $459 million in health impact costs, respectively.[134]

8.1 Air Quality

Burning pipeline gas for the use of indoor appliances impacts outdoor air quality, because furnaces, boilers, and domestic hot water heaters are generally vented outdoors and thereby release various air pollutants into the atmosphere.[135] Annually, residential natural gas combustion in Minnesota emits 5,822 tons of NO_X, while natural gas combustion in the commercial sector emits another 1,065 tons.[136] After NO_X from appliances is released outdoors, it reacts in the atmosphere and forms secondary pollutants such as O_3 and $PM_{2.5}$.[137] This pollution worsens air quality, especially in neighborhoods with higher rates of reliance on gas, and can cause various negative health effects as discussed in the previous section.

As required by the *Clean Air Act*, the EPA sets enforceable standards for outdoor levels of six criteria air pollutants that can be harmful to the public: O_3, PM, CO, lead, SO_2, and NO_2. These standards have been in place for decades and are reviewed and updated periodically based on available health and environmental information. The EPA also tracks other hazardous air pollutants in a Toxics Release Inventory, among other systems and processes.[138]

We conducted an analysis to estimate the health impacts and benefits of reduced gas usage in residences. For earlier sections of this report, we modeled two building decarbonization scenarios: one focusing on aggressive building electrification and another that included the replacement of natural gas with RNG as a supplement to building electrification. We used those results as inputs for estimating emissions reductions and an analysis of health benefits in 2030, 2040, and 2050 interval years, using EPA's COBRA tool. Overall, the analysis shows meaningful potential for decarbonization efforts to produce positive health impacts based on reductions in outdoor air pollution. In both scenarios, benefits are projected to provide at least $15 million in health benefits by 2030, and at least $56 million by 2050 (see Table 30 below). Our analysis projects the Full Electrification scenario will reduce health externalities to a greater level than the Electrification + Alternative Fuels scenario and could provide a

[134] Rocky Mountain Institute. 2021. "What is the Health Impact of Buildings in Your State?" Available at: https://rmi.org/health-air-quality-impacts-of-buildings-emissions#MN.

[135] Zhu, Y., Connoly, R., Lin, Y., Mathew, T., Wang, Z. 2020. "Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California" UCLA Fielding School of Public Health Department of Environmental Services. Accessed at: https://coeh.ph.ucla.edu/2020/04/29/study-gas-powered-appliances-may-be-hazardous-for-your-health/.

[136] U.S. Environmental Protection Agency. 2017. "National Emissions Inventory Data" *Sector Summaries*. Accessed at: https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data.

[137] U.S. Environmental Protection Agency. 2023 "Basic Information about NO_2" *Nitrogen Dioxide (NO_2) Pollution*. Accessed at: https://www.epa.gov/no2-pollution/basic-information-about-no2.

[138] U.S. Environmental Protection Agency. 2023. "Outdoor Air Quality" *Report on Environment*. Available at: https://www.epa.gov/report-environment/outdoor-air-quality.

high estimate of $130 million in health benefits by 2050.[139] Minnesota already recognizes the financial impact of emissions, and this analysis provides additional context in which to quantify environmental externalities. The savings achieved by reducing the environmental externalities identified by this analysis can inform decision-making related to the total costs of various decarbonization efforts in the state.

8.1.1 Analytical Process

The results of the Full Electrification and Electrification + Alternative Fuels scenarios included overall annual CO_2 emissions projections from the baseline year, 2021, through 2050. We calculated the percentage reductions for CO_2 in the selected interval years of 2030, 2040, and 2050 based on that 2021 baseline year. We then applied the percentage reductions identified for each milestone year to several types of pollutants, namely $PM_{2.5}$, SO_2, NO_X, ammonia (NH_3), and VOCs.[140] We used these emission reduction estimates as inputs into COBRA.

We assumed the same percentage reduction for each pollutant available in COBRA: $PM_{2.5}$, SO_2, NO_X, NH_3, VOC. Table 30 shows the percentage reduction used for each interval year in each scenario.

Table 30. Emissions reduction percentage COBRA inputs applied to each pollutant

	Full Electrification	Electrification + Alternative Fuels
2030	27.8%	25.3%
2040	74.4%	69.2%
2050	99.8%	96.8%

The estimates from our COBRA analysis are based on a scenario restricted to the state of Minnesota and residential natural gas combustion impacts. We also defined the scenario using the default baseline year in COBRA (2023) and a 3 percent discount rate.[141]

Our analysis did not include impacts related to reduced methane leaks, only those related to emissions reductions from natural gas combustion in the residential sector. It also did not include benefits from reductions in commercial building natural gas combustion.

8.1.2 Results

The COBRA analysis provided outputs for both the monetary value in 2017 dollars and change in incidence for several health outcomes, as well as a high and low total health benefit estimate. COBRA estimates the number of cases avoided for several different health benefits. These include avoided deaths, hospital admissions for certain symptoms and episodes, asthma-related endpoints, other types

[139] COBRA monetary results are presented in 2017 dollars.

[140] U.S. Environmental Protection Agency. 2021. "What is COBRA?" *CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool COBRA*. Available at: https://www.epa.gov/cobra/what-cobra.

[141] COBRA has three baseline years that it provides: 2016, 2023, and 2028. 2023 is the year closest to the BDC baseline.

of respiratory symptoms, and work-loss days. COBRA calculates monetary values for those health benefits based on available data related to hospital charges and costs, median annual earnings, and the value of a statistical life.[142] COBRA is a preliminary screening tool that can be used to identify scenarios that may benefit from further evaluation. COBRA does not provide granular or holistic evaluations of air quality; rather it provides a wide stroke of information on the benefits of improved air quality that is useful for discussion of externalities and health benefits derived from emissions reductions. It should be noted that the COBRA analysis could underestimate true health effects and healthcare costs since it does not model all air pollution (e.g. ozone) and all health outcomes affected by air pollution (e.g. chronic obstructive pulmonary disease and preterm birth).

Table 31 below shows the high and low values for total health benefits in monetary terms for each interval year in both the Full Electrification and Electrification + Alternative Fuels scenarios. In both scenarios, the analysis projects approximately $15 million in health benefits by 2030 and approximately $56 to $58 million by 2050, showing that decarbonization will yield substantial health benefits over the coming decades. The Full Electrification scenario is projected to reduce health externalities to a greater level than the Electrification + Alternative Fuels scenario and could provide a high estimate of $130 million in health benefits by 2050. That Full Electrification scenario estimate is 1.03 percent greater than the high estimate in the Electrification + Alternative Fuels scenario for 2050. On a more granular level, the more ambitious Full Electrification scenario produces a greater estimate of health benefits for every single category of benefits available in COBRA for every year analyzed.

It is important to note that COBRA provides a snapshot of the monetized benefits and incidence reductions achieved for each milestone year if the assumed emissions reductions are realized compared to the baseline year selected. The baseline year 2023 was the baseline offered by COBRA that was closest to the baseline available in Synapse's data, and the analysis used a 3 percent discount rate.

Table 31. Snapshot of estimated total health benefits in Minnesota per milestone year (in million $)

	Full Electrification		Electrification + Alternative Fuels	
	High Value	Low Value	High Value	Low Value
2030	$36	$16	$15	$15
2040	$97	$43	$90	$40
2050	$130	$58	$126	$56

The following three tables show the projected change in incidence for select health outcomes in both the Full Electrification and Electrification + Alternative Fuels scenarios over the interval years of 2030, 2040, and 2050.

[142] U.S. Environmental Protection Agency. 2021. "How COBRA Works" Available at: https://www.epa.gov/cobra/how-does-cobra-work-0.

Table 32. 2030 estimated reduction in incidence for specific health impacts

	Full Electrification	Electrification + Alternative Fuels
Mortality	1.4 / 3.2	1.3 / 2.9
Upper Respiratory Symptoms	43.5	39.6
Asthma, Emergency Room Visits	0.5	0.5
Work-Loss Days	215	196

Table 33. 2040 estimated reduction in incidence for specific health impacts

	Full Electrification	Electrification + Alternative Fuels
Mortality	3.8 / 8.7	3.6 / 8.0
Upper Respiratory Symptoms	116.6	108.5
Asthma, Emergency Room Visits	1.4	1.3
Work-Loss Days	576	536

Table 34. 2050 estimated reduction in incidence for specific health impacts

	Full Electrification	Electrification + Alternative Fuels
Mortality	5.2 / 11.7	5.001 / 11.3
Upper Respiratory Symptoms	156.4	151.7
Asthma, Emergency Room Visits	1.9	1.8
Work-Loss Days	774	750

See Technical Appendix B. for full summaries of the COBRA results.

8.2 Indoor Air Quality

Burning pipeline gas worsens indoor air quality inside buildings as well. The indoor and outdoor air quality impacts can also overlap, particularly in poorly insulated buildings that allow indoor air pollutants into the outdoors or outdoor pollutants into the home. Unlike for outdoor air quality, the EPA does not have standards for indoor air quality levels of pollution.[143] EPA studies of human exposure to air pollutants suggest that indoor levels of pollutants may be two to five times—and occasionally more than 100 times—higher than outdoor levels. The fact that people spend 90 percent of their time inside makes

[143] Lebel E., Finnegan, C., Ouyang, Z., and Jackson, R. B. 2022. "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes" *Environmental Science & Technology* 56 (4): 2529-2539. Available at: https://pubs.acs.org/doi/epdf/10.1021/acs.est.1c04707.

both this lack of good data and the estimated levels of air pollution serious causes for concern.[144] Indoor air quality tends to be worse and have a greater impact on human health than outdoor air quality.[145]

Gas appliances and other sources of indoor air pollution can affect indoor air quality at varying levels depending on the age of the appliance or its level of maintenance. Gas stoves in particular have a substantial impact on indoor air quality and the health of residents who cook with gas. Heating appliances tend to vent emissions outside rather than emit them directly into homes as stoves do. Emissions from stoves can be mitigated by technology such as range hoods, though their effectiveness can vary based on age and maintenance, and many kitchens lack the technology altogether.[146]

People also tend to interact more with their stoves than other gas appliances, often using them daily and standing directly over them while they are in use.[147] Cooking with gas impacts the levels of multiple pollutants in homes and commercial kitchens. Gas stoves generally elevate the risk of CO and can achieve levels of $PM_{2.5}$ emissions that are twice as high as electric stoves. Gas stoves can produce high exposure levels of formaldehyde after simmering on low heat for hours without proper ventilation. Researchers have also found that NO_2 concentrations dropped by up to 51 percent in kitchens after replacing a gas stove with an electric one.[148] In homes with poor ventilation, small kitchens, or without the use of range hoods, using a gas stove or oven can cause concentrations of NO_2 to surpass the EPA's outdoor guidelines for one-hour exposure within several minutes.[149] In a 2022 study examining gas stove emissions in the United States, analysts examined patterns in emissions. Stoves tend to emit NO_X in a linear pattern compared to when and how much gas is burned. Generally, 0.8–1.3 percent of the gas emitted by natural gas stoves is unburned methane. The study found that 76 percent of methane

[144] U.S. Environmental Protection Agency. 2022. "Why Indoor Air Quality is Important to Schools" *Indoor Air Quality in Schools*. Available at: https://www.epa.gov/iaq-schools/why-indoor-air-quality-important-schools.

[145] National Institute of Environmental Health Services. 2023. "Indoor Air Quality" *Health and Education.* Available at: https://www.niehs.nih.gov/health/topics/agents/indoor-air/index.cfm.

[146] Zhu, Y., Connoly, R., Lin, Y., Mathew, T., Wang, Z. 2020. "Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California" UCLA Fielding School of Public Health Department of Environmental Services. Accessed at: https://coeh.ph.ucla.edu/2020/04/29/study-gas-powered-appliances-may-be-hazardous-for-your-health/; Lebel E., Finnegan, C., Ouyang, Z., and Jackson, R. B. 2022. "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes" *Environmental Science & Technology* 56 (4): 2529-2539. Available at: https://pubs.acs.org/doi/epdf/10.1021/acs.est.1c04707.

[147] Lebel E., Finnegan, C., Ouyang, Z., and Jackson, R. B. 2022. "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes" *Environmental Science & Technology* 56 (4): 2529-2539. Available at: https://pubs.acs.org/doi/epdf/10.1021/acs.est.1c04707.

[148] Paulin, L.M., Diette G.B., Scott M., McCormack, M.C., Matsui, E.C., Curtin-Brosnan, J., Williams, D.L., Kidd-Taylor, A., Shea, M., Breysse, P.N., Hansel, N.N. 2014. "Home interventions are effective at decreasing indoor nitrogen dioxide concentrations" *Indoor Air.* 24 (4): 416-24.

[149] Lebel E., Finnegan, C., Ouyang, Z., and Jackson, R. B. 2022. "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes" *Environmental Science & Technology* 56 (4): 2529-2539. Available at: https://pubs.acs.org/doi/epdf/10.1021/acs.est.1c04707.

emissions coming from stoves were from when stoves were off, meaning these appliances can cause serious impacts on air quality when they are not in use.[150]

This pollution leads to significant health impacts and remains present even when RNG is burned, because it continues the use of methane, causing NO_X and other harmful pollutant emissions.[151] One study found that 12.7 percent of current childhood asthma across the United States is attributed to gas stove use, which is similar to the childhood asthma burden attributed to secondhand smoke exposure.[152] Gas stoves have additionally been found to emit benzene, a carcinogen identified by the EPA known to increase risk of leukemia.[153] A single gas burner on high or an oven set to 350 °F raised kitchen benzene concentrations above the upper range of indoor benzene concentrations attributable to secondhand tobacco smoke (0.34–0.78 ppbv) and above the median indoor benzene concentration measured in the United States, Canada, Western Europe, Japan, South Korea, Hong Kong, and Australia.[154]

8.3 Equity

The detrimental effects of air pollution disproportionately impact historically marginalized communities, often identified as environmental justice communities or areas. Minnesota has defined "environmental justice area" as an area in the state that meets one or more of the following criteria:

- 40 percent or more of the area's total population is non-white;
- 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level;
- 40 percent or more of residents over the age of five have limited English proficiency; or
- The area is located within Indian country, as defined in USC, title 18, section 1151.[155]

The recent 100% Carbon-Free Electricity Bill has brought equity to the forefront of energy and

150 *Ibid*.

151 Natural Resources Defense Council. 2020. "A pipe dream or climate solution? The opportunities and limits of biogas and synthetic gas to replace fossil gas." Accessed: https://www.nrdc.org/sites/default/files/pipe-dream-climate-solution-bio-synthetic-gas-ib.pdf.

152 Gruenwald, T., Seals, B.A., Knibbs L.D., Hosgood, H.D. 3rd. *Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States*. Int J Environ Res Public Health. 2022 Dec 21; 20 (1): 75.

153 Lebel, E.D., Michanowicz, D.R., Bilsback, K.R., Hill, L.A.L., Goldman, J.S.W., Domen, J.K., Jaeger, J.M., Ruiz, A., Shonkoff, S.B.C. Composition, Emissions, and Air Quality Impacts of Hazardous Air Pollutants in Unburned Natural Gas from Residential Stoves in California. Environ Sci Technol. 2022 Nov 15; 56 (22): 15828-15838.

154 Kashtan, Y.S., Nicholson, M., Finnegan, C., Ouyang, Z., Lebel, E.D., Michanowicz, D.R., Shonkoff, S.B.C., Jackson, R.B. Gas and Propane Combustion from Stoves Emits Benzene and Increases Indoor Air Pollution. Environ Sci Technol. 2023 Jul 4; 57 (26): 9653-9663.

155 Minnesota Statutes Section 216B.1691 Renewable Energy Objectives.

environmental discussions by requiring the PUC to consider impacts on environmental justice areas in decision-making.[156]

Across the United States, 44 percent of low-income residential housing relies on natural gas for heat.[157] Low-income residents often live in lower quality homes that are older and leakier, which means they tend to suffer from higher effects of outdoor air pollution influences while inside the home.[158] Studies have shown that low-income households in multifamily buildings have higher concentrations of combustion byproducts due to smaller unit sizes and often inadequate ventilation. These factors elevate the source strength of pollutants, especially NO_2 and $PM_{2.5}$.[159] This effect is often enhanced by the fact that lower-income populations tend to also live in small homes with a greater occupant density.

Air pollution from burning pipeline gas also has a starkly disproportionate impact along racial divides. Residential gas combustion showed the highest relative racial-ethnic disparity of any category studied in an RMI analysis, including power plants, vehicles, and industrial sources. A recent peer-reviewed study found that people of color are exposed to twice as much outdoor $PM_{2.5}$ pollution from residential gas combustion as white people. Communities of color experience 38 percent higher exposure to NO_2 (a main pollutant emitted by appliances and one that is linked to asthma development) in turn creating disproportionate health impacts in these communities. Black populations experience over three times as many deaths per 100,000 people that are attributable to $PM_{2.5}$ emissions when compared to other populations.[160]

These negative health impacts may cause additional economic burdens on these households when people miss days of work or incur medical bills as a result of these issues. These disparities make it essential to address the negative health impacts of continued reliance on pipeline gas and to ensure conversations about equity remain at the forefront of energy-related decision-making. Although the greenhouse gas impacts of RNG have been evaluated, there has been little or no consideration of the air quality impacts which may continue to affect the households that continue to utilize RNG in the Electrification + Alternative Fuels Scenario and similarly prolong health disparities resulting from indoor RNG combustion.

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156 *Ibid*.

157 Tan, Y. A., Jung, B. 2021 *Decarbonizing Homes: Improving Health in Low-Income Communities through Beneficial Electrification*. Rocky Mountain Institute. Available at: http://www.rmi.org/insight/decarbonizing-homes.

158 Adamkiewicz, G. et al. 2011. "Moving Environmental Justice Indoors: Understanding Structural Influences on Residential Exposure Patterns in Low-Income Communities" *American Journal of Public Health* 101 (1). Available at: https://ajph.aphapublications.org/doi/full/10.2105/AJPH.2011.300119.

159 *Ibid*.

160 Industrial Economics, Incorporated. 2022. "Analysis of $PM_{2.5}$-Related Health Burdens Under Current and Alternative NAAQs" *Prepared for Environmental Defense Fund*. Available at: https://www.globalcleanair.org/files/2022/05/Analysis-of-PM2.5-Related-Health-Burdens-Under-Current-and-Alternative-NAAQS.pdf.

Technical Appendix A. Building Decarbonization Model Assumptions

For space heating heat pumps, we developed forecasts of average annual energy efficiencies—expressed as COP—separately by sector, technology type (ducted or ductless), and system type (electric resistance backup or fuel backup). Table 35 and Table 36 below show these forecasts, which we developed based on our assessment of various data sources.

Table 35. Synapse projection of residential heat pump COP

Type	2020	2030	2040	2050	Notes
Ductless ASHP – Electric Resistance Backup	2.5	3.1	3.5	3.6	Based on our estimate of the current COP value in Minnesota and NREL EFS COP trajectory
Ducted ASHP – Electric Resistance Backup	2.2	2.7	3.1	3.2	Assumes efficiencies of ducted systems are about 12 percent less than ductless systems based on Cadmus (2022) Residential ccASHP Building Electrification Study
Ductless ASHP – Dual-Fuel, Gas Backup	2.4	2.9	3.3	3.4	Assumes 29% heating load served by gas backing heating system
Ducted ASHP – Dual-Fuel, Gas Backup	2.1	2.6	2.9	3.0	Assumes 29% heating load served by gas backing heating system
GSHP	3.43	4.29	4.86	5.03	"All Systems" COP from https://mn.gov/commerce-stat/pdfs/card-residential-gound-source-heat-pump-study.pdf

Table 36. Synapse projection of commercial heat pump COP

Type	2020	2030	2040	2050	Notes
Ductless ASHP – Electric Resistance Backup	3.0	3.7	4.2	4.3	Assumes commercial systems are 20% more efficient than residential systems due to the availability of high temperature heat sources (including VRF's high COP value due to simultaneous heating and cooling functions)
Ducted ASHP – Electric Resistance Backup	2.6	3.2	3.7	3.8	Assumes commercial systems are 20% more efficient than residential systems due to the availability of high temperature heat sources (including VRF's high COP value due to simultaneous heating and cooling functions)
Ductless ASHP – Dual-Fuel, Gas Backup	2.8	3.5	4.0	4.1	Assumes 29% heating load served by gas backing heating system
Ducted ASHP – Dual-Fuel, Gas Backup	2.5	3.1	3.5	3.6	Assumes 29% heating load served by gas backing heating system
GSHP	3.43	4.29	4.86	5.03	"All Systems" COP from https://mn.gov/commerce-stat/pdfs/card-residential-gound-source-heat-pump-study.pdf

For HPWHs, we developed average annual COP values separately for residential and commercial buildings, as shown in Table 37 below.

Table 37. Synapse projection of HPWH COP

Technology	2020	2030	2040	2050	Notes
HPWH - Residential	2.3	2.6	2.8	2.8	Based on our estimate of the current COP value in Minnesota and NREL EFS COP trajectory
HPWH - Commercial	2.3	2.4	2.8	2.8	Same as the RES COP projection for HPWH

To model the electrification of gas cooking, we assumed that electric cooktops and ovens replace gas appliances over time. Electric cooktop efficiencies were modeled to be an average of induction and electric resistance. Table 38 presents efficiencies of cooking equipment used in our analysis. While we derived these efficiencies for residential cooking equipment, we assumed the same efficiencies for commercial cooking equipment.

Table 38. Efficiencies of cooktops and ovens

	Cooktop Efficiency	Oven Efficiency	Combined Efficiency
Gas	27.2%	22.4%	25.5%
Electricity (resistance cooktop)	67.0%	29.0%	47.5%
Electricity (induction cooktop)	85.0%	29.0%	53.0%

Source: U.S. Department of Energy. 2016. Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment: Commercial and Industrial Equipment: Residential Conventional Cooking Products; Frontier Energy. 2019. Residential Cooktop Performance and Energy Comparison.

For the electrification of clothes drying, we assumed that standard electric dryers and heat pump dryers replace gas dryers in residential buildings. We did not explicitly model commercial drying consumption. Dryer efficiencies are shown in Table 39.

Table 39. Efficiencies of dryers

	Efficiency	Notes
Gas	60%	Bendt, P. 2010. Are We Missing Energy Savings in Clothes Dryers?
Electric dryer	67%	Bendt, P. 2010. Are We Missing Energy Savings in Clothes Dryers? (https://www.aceee.org/files/proceedings/2010/data/papers/2206.pdf); 3.73 CEF (lbs/kWh) federal minimum efficiency
Heat pump dryer	87%	Average CEF of 6 based on EnergyStar products; 45% more efficient than gas units (3.3 minimum CEF)

Technical Appendix B. COBRA Results

Technical Appendix B contains the full summaries of the COBRA results from Chapter 8. Synapse ran scenarios for 2030, 2040, and 2050 based off COBRA's default 2023 baseline year, using percentage reductions calculated from the projected emissions resulting from BDC analyses used in earlier tasks. Synapse conducted BDC analyses to model various impacts of two decarbonization scenarios: Full Electrification and Electrification + Alternative Fuels. BDC results included annual emissions projections from the baseline year, 2021, through 2050. Synapse calculated the percentage reductions in the selected interval years of 2030, 2040, and 2050 based on that 2021 baseline year. Those percentages were then used as inputs in the COBRA analysis. The baseline year 2023 was the baseline offered by COBRA that was closest to the baseline available in Synapse's data. The COBRA analyses also used a 3 percent discount rate.[161]

Synapse assumed the same percentage reduction for each pollutant available in COBRA: $PM_{2.5}$, SO_2, NO_X, NH_3, VOC. Table 40 shows the percentage reduction used for each interval year in each scenario.

Table 40. Emissions reduction percentage COBRA inputs

	Full Electrification	Electrification + Alternative Fuels
2030	27.78%	25.28%
2040	74.38%	69.24%
2050	99.83%	96.78%

The COBRA results show two ways of considering health benefits from air pollution reduction: change in incidence and monetary value. To calculate the change in incidence, or number of new cases of a particular health endpoint, COBRA calculates statistical risk reductions which are then aggregated over the population. Monetary values of the changes in incidence for different health endpoints are presented in 2017 dollars.[162] The following tables show the summary of health benefits for each of the interval years in each scenario.

[161] This discount rate was identified as an acceptable discount rate to use for externality cost calculations in Minnesota PUC's 2018 decision, but 7 percent was not. The two available options for discount rates in COBRA are 3 percent and 7 percent. *Order Updating Environmental Cost Values*, Docket No. E-999/CI-14-643 Minnesota Public Utilities Commission (January 3, 2018).

[162] U.S. Environmental Protection Agency. "COBRA Web Edition" CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). Available at: https://cobra.epa.gov/.

Table 41. 2030 health benefits: Full Electrification scenario

	Change in Incidence	Monetary Value
Mortality	1.436 / 3.247	$15,711,133 / $35,530,090
Nonfatal Heart Attacks	0.152 / 1.411	$24,324 / $225,995
Infant Mortality	0.009	$107,934
Hospital Admits, All Respiratory	0.261	$13,934
Hospital Admits, Cardiovascular (except heart attacks)	0.273	$9,972
Acute Bronchitis	2.413	$1,489
Upper Respiratory Symptoms	43.53	$1,860
Lower Respiratory Symptoms	30.652	$828
Emergency Room Visits, Asthma	0.515	$290
Asthma Exacerbation	44.698	$3,317
Minor Restricted Activity Days	1264.993	$110,895
Work-Loss Days	215.43	$43,126

	High Value	Low Value
Total Benefits	$36,049,730	$16,029,102

Table 42. 2040 health benefits: Full Electrification scenario

	Change in Incidence	Monetary Value
Mortality	3.844 / 8.692	$42,064,088 / $95,120,769
Nonfatal Heart Attacks	0.407 / 3.777	$65,125 / $604,981
Infant Mortality	0.024	$288,979
Hospital Admits, All Respiratory	0.699	$37,307
Hospital Admits, Cardiovascular (except heart attacks)	0.731	$26,699
Acute Bronchitis	6.460	$3,986
Upper Respiratory Symptoms	116.56	$4,980
Lower Respiratory Symptoms	82.058	$2,216
Emergency Room Visits, Asthma	1.38	$778
Asthma Exacerbation	119.676	$8,881
Minor Restricted Activity Days	3386.772	$296,901
Work-Loss Days	576.78	$115,465

	High Value	Low Value
Total Benefits	$96,511,942	$42,915,404

Table 43. 2050 health benefits: Full Electrification scenario

	Change in Incidence	Monetary Value
Mortality	5.159 / 11.666	$56,455,398 / $127,660,265
Nonfatal Heart Attacks	0.546 / 5.069	$87,407 / $811,900
Infant Mortality	0.032	$387,850
Hospital Admits, All Respiratory	0.939	$50,072
Hospital Admits, Cardiovascular (except heart attacks)	0.981	$35,834
Acute Bronchitis	8.669	$5,350
Upper Respiratory Symptoms	156.44	$6,684
Lower Respiratory Symptoms	110.126	$2,974
Emergency Room Visits, Asthma	1.852	$1,044
Asthma Exacerbation	160.623	$11,920
Minor Restricted Activity Days	4545.448	$398,476
Work-Loss Days	774.12	$154,969

	High Value	Low Value
Total Benefits	$129,527,336	$57,597,977

Table 44. 2030 health benefits: Electrification + Alternative Fuels scenario

	Change in Incidence	Monetary Value
Mortality	1.307 / 2.955	$14,297,279 / $32,332,817
Nonfatal Heart Attacks	0.138 / 1.284	$22,135 / $205,659
Infant Mortality	0.008	$98,220
Hospital Admits, All Respiratory	0.238	$12,680
Hospital Admits, Cardiovascular (except heart attacks)	0.248	$9,074
Acute Bronchitis	2.196	$1,355
Upper Respiratory Symptoms	39.62	$1,693
Lower Respiratory Symptoms	27.894	$753
Emergency Room Visits, Asthma	0.469	$264
Asthma Exacerbation	40.676	$3,018
Minor Restricted Activity Days	1151.156	$100,916
Work-Loss Days	196.04	$39,245

	High Value	Low Value
Total Benefits	$32,805,696	$14,586,634

Table 45. 2040 health benefits: Electrification + Alternative Fuels scenario

	Change in Incidence	Monetary Value
Mortality	3.578 / 8.092	$39,157,464 / $88,548,496
Nonfatal Heart Attacks	0.378 / 3.516	$60,625 / $563,186
Infant Mortality	0.022	$269,010
Hospital Admits, All Respiratory	0.651	$34,729
Hospital Admits, Cardiovascular (except heart attacks)	0.681	$24,854
Acute Bronchitis	6.014	$3,711
Upper Respiratory Symptoms	108.50	$4,636
Lower Respiratory Symptoms	76.388	$2,063
Emergency Room Visits, Asthma	1.285	$724
Asthma Exacerbation	111.406	$8,267
Minor Restricted Activity Days	3152.752	$276,386
Work-Loss Days	536.93	$107,486

	High Value	Low Value
Total Benefits	$89,843,547	$39,949,955

Table 46. 2050 health benefits: Electrification + Alternative Fuels scenario

	Change in Incidence	Monetary Value
Mortality	5.001 / 11.310	$54,730,741 / $123,760,833
Nonfatal Heart Attacks	0.529 / 4.914	$84,737 / $787,104
Infant Mortality	0.031	$376,001
Hospital Admits, All Respiratory	0.910	$48,543
Hospital Admits, Cardiovascular (except heart attacks)	0.951	$34,739
Acute Bronchitis	8.404	$5,186
Upper Respiratory Symptoms	151.66	$6,480
Lower Respiratory Symptoms	106.762	$2,883
Emergency Room Visits, Asthma	1.796	$1,012
Asthma Exacerbation	155.716	$11,555
Minor Restricted Activity Days	4406.593	$386,303
Work-Loss Days	750.47	$150,235

	High Value	Low Value
Total Benefits	$125,570,875	$55,838,415