AGA American Gas Association

Grounded in Reality

Research Methodology

This document reviews the methodology used by the American Gas Association (AGA) in its *Grounded in Reality: Implications of Electrification* analyses. The purpose of the study is to evaluate the effects of a policy applied in select cities in the United States that would require the conversion of the housing and commercial building stocks from natural gas to electricity over the next 20 years. AGA also utilized FTI Consulting to perform additional economic impact analysis based on the results of the AGA analysis.

AGA utilized the following general steps in its evaluation:

1. Determine the 10-year average space heating and non-space heating energy requirements based on the efficiency of end-use equipment in residential and commercial buildings.
2. Determine the 20-year impact to buildings stocks based on current residential and commercial buildings using natural gas.
3. Estimate appliance and installation costs by fuel type in new and existing buildings based on the ICF *Implications of Policy-Driven Residential Electrification* 2018 Report.
4. Estimate impact on emissions due to increased electric end-use requirements and natural gas end-use.
5. Estimate first-year consumer costs and a 20 year cost forecast based on the 2021 EIA *Annual Energy Outlook* and NREL's Cambium Database.

The model uses several sources for data and modeling tools, including the U.S. Energy Information Administration (EIA), National Oceanic Atmospheric Administration (NOAA) and the National Renewable Energy Lab's (NREL) Regional Energy Deployment System (ReEDS), as referenced throughout the document. Additionally, individual city-level outputs are included in Appendices B-E.

Baseline Scenario: Continued use of natural gas in homes and businesses

- AGA assumed current natural gas building stock trends based on the last ten years would continue over the next twenty years.
- Customers installing new or replacement furnaces and water heaters would use a 96% efficiency furnace and an 82% efficiency water heater.
- CO_2 emissions from natural gas remain at the current EPA level of 117 lbs. per MMBtu. No additional inclusion of renewable natural gas or other low carbon fuel for direct use appliances. *Other greenhouse gases were not modeled because the NREL ReEDS model and Cambium database do not include them for cross comparison.*

- Future increases to natural gas prices based on 2021 EIA Annual Energy Outlook forecast for regional end-use prices through 2050.

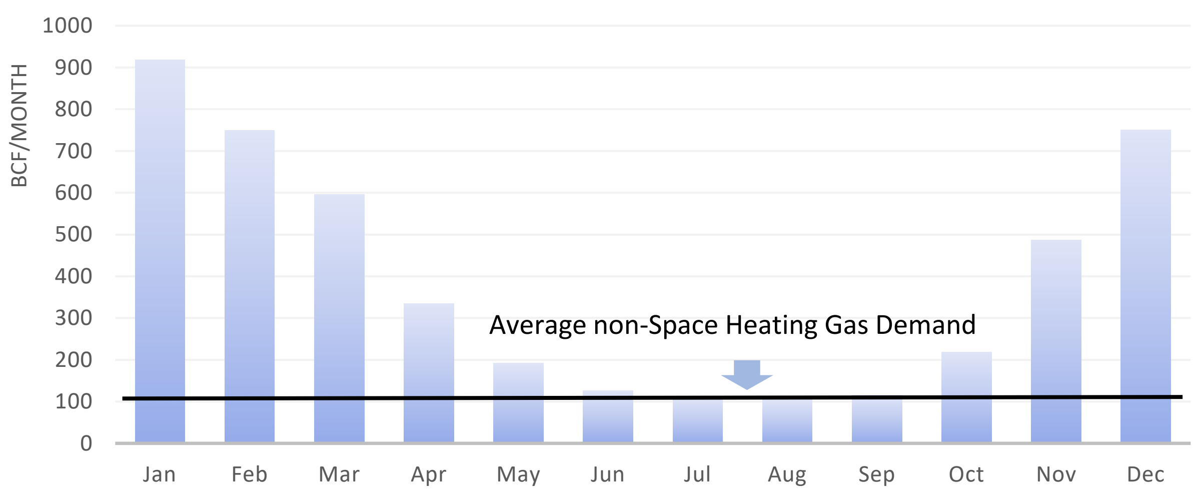
Electrification Scenario: Mandated electrification of homes and businesses

- No new natural gas residential or commercial customers are allowed starting in 2022.
- All homes and businesses must install a cold climate heat pump rated 300 percent efficient, a heat pump water heater rated 200 percent efficient, a 75 percent efficient electric dryer, and a 393 percent efficient electric stove (if they were using natural gas before).
- CO_2 emissions for the power generation sector are based on the "low cost/high penetration" renewables scenario from the NREL Cambium database. Emissions were calculated by matching hourly energy requirements with the hourly long-term marginal rate for each year modeled.
- Future increases to electricity prices are based on the combination of wholesale prices provided by NREL's Cambium database and EIA's AEO 2021 forecast for transmission and distribution costs.

Calculating Space Heating Energy Requirements and Heat Pump Performance in Residential and Commercial Buildings

Space heating energy requirement is estimated by subtracting average summer consumption from monthly consumption over a year. Summer consumption functions as an estimate for baseload consumption because there is little weather-driven space heating demand during these months. AGA used a 10-year average to normalize consumption while also accounting for any real-world improvements in gas appliance efficiency after recent winters. Figure 1 shows the relationship between base load and heating load for an average year.

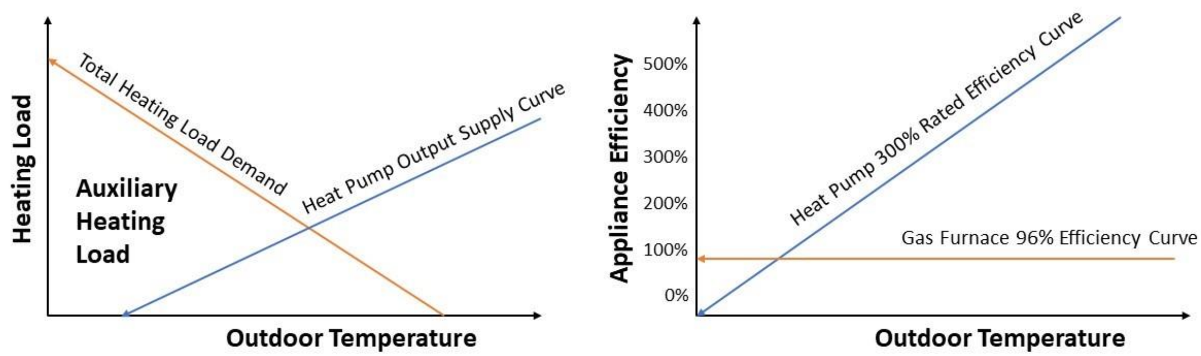
Figure 1 – 10-year average residential natural gas consumption for the entire US by month



In the studied electrification scenario, the analysis assumes the installation of heat pumps in both new construction and converted buildings with a nameplate efficiency of 300% at 35°F and an output of 100% of the demand load at or above 35°F. However, their performance and maximum output decrease as the temperature drops from 35°F. The maximum output and efficiency at 35°F could be increased by oversizing the unit at an increased cost to consumers.

The RE-GEN model from the Electric Power Research Institute (EPRI) was used to estimate the 300% efficient heat pump total output and overall efficiency curve from 35°F, where 100% of the load is met, to -20°F, where 0% of the load is met.[1] Furthermore, our methodology assumes energy demand is fully met, and any output gap from degraded heat pump performance is met with a 99% efficiency backup electrical resistance unit. AGA's model did not factor in any additional degradation of heat pump or gas furnace performance over the life of the unit, and it is assumed to operate at its full potential throughout the lifespan of the appliance. Figure 2 shows the relationship between outdoor temperature and heat pump efficiency.

Figure 2 – Theoretical end-use efficiency of heat pump and gas furnace



In the Electrification scenario, the analysis assumes customers would convert from a retired 80% efficient gas-fired unit to a 300% (3.0 COP) rated heat pump, a heat pump, water heater, and all-electric appliances. The energy requirements of these non-space heating appliances are a regional weighted average derived from the EIA's Residential Energy Consumption Survey (RECS)[2] and Commercial Building Energy Consumption Survey (CBECS).[3] Finally, the baseline gas scenario assumes that customers keep their gas appliances but upgrade the furnace to a 96% efficient gas-fired condensing unit and the gas water heater to an 82% efficient unit.

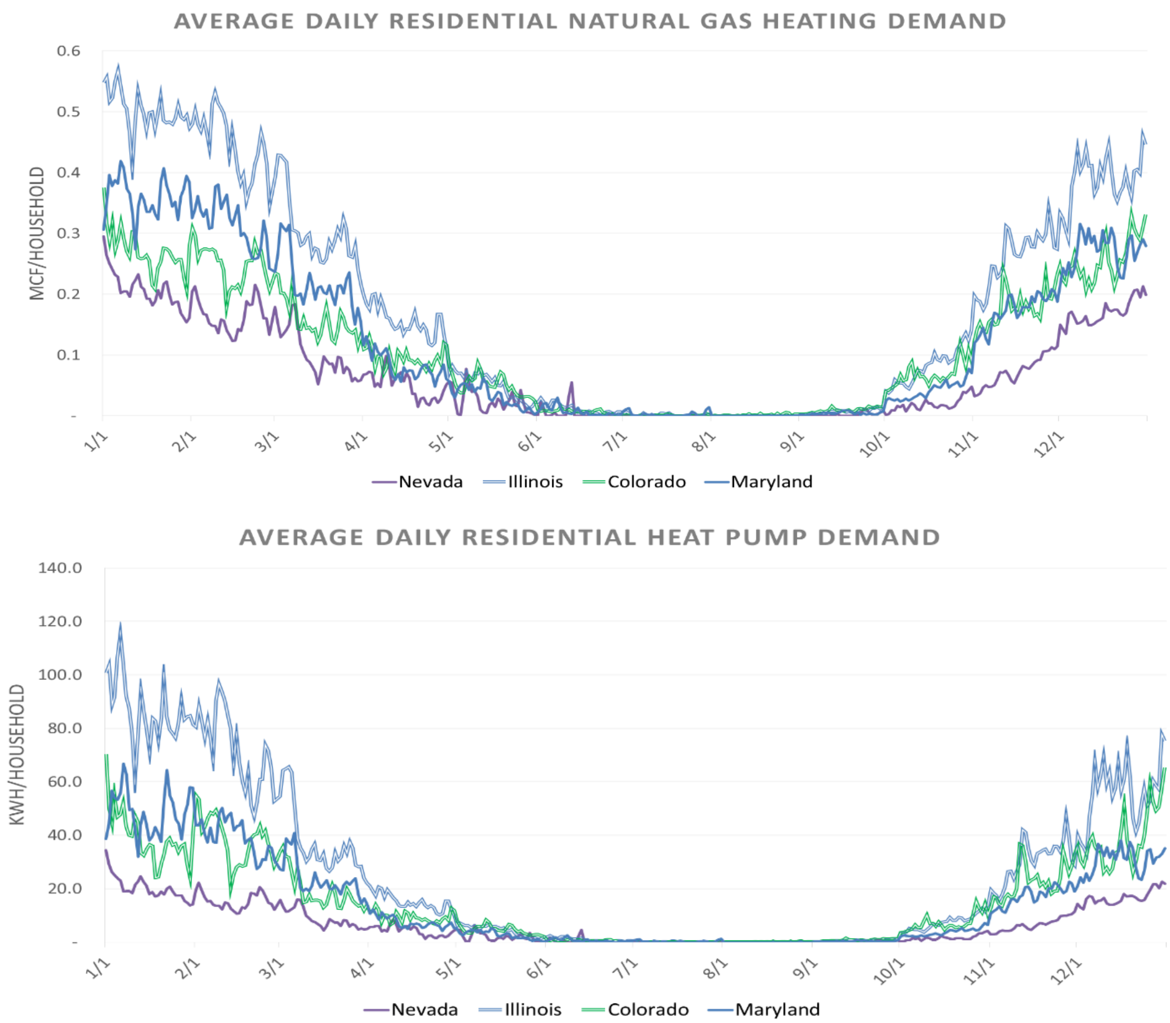
Because the efficiency and total output of a heat pump space heater are dependent on outdoor air temperature, the monthly model for space heating demand must be converted into an hourly model. The model estimates the hourly consumption by weighting each hour of the day by the total number of hourly heating degree days (HDD) recorded. The hourly HDD values are developed using NOAA's local dry air temperature records for each city and state. The heat pump energy requirement is then determined based on the estimated hourly space heating demand of gas customers and the model from EPRI, which relies on the same dry air temperature to determine overall efficiency and output at any given time in the model. Figure 3 shows the average daily residential heating energy requirement for gas furnaces and heat pumps for some analyzed cities.

[1] Electric Power Research Institute, "US-REGEN Model Documentation," https://www.epri.com/#/pages/product/3002010956/?lang=en-US

[2] "2015 Residential Energy Consumption Survey," *U.S. Energy Information Administration*, https://www.eia.gov/consumption/residential/data/2015/

[3] "2012 Commercial Buildings Energy Consumption Survey," *U.S. Energy Information Administration*, https://www.eia.gov/consumption/commercial/data/2012/

Figure 3 – Local average customer's daily high-efficiency gas and heat pump usage



AGA did not model a "hybrid" approach option for space heating where the auxiliary space heating load would be managed by a form of space heating that is not electrical resistance. By installing a dual fuel hybrid heat pump that includes a natural gas or propane burner tip, customers could improve operating costs and emissions compared to an all-electric option. Existing gas customers using a furnace could also supplement space heating with a heat pump for parts of the winter but continue to use the gas furnace during the peak winter heating season.

Based on the U.S. Census Bureau, Characteristics of New Housing Survey, natural gas furnaces were installed in 52% of all homes between 2011 and 2019, with all-electric heat pumps in 31% and electrical resistance in 9%.[4] The remaining 8% of homes were built with either propane, fuel oil, or a hybrid system. Between 2011 and 2019, nearly 458 thousand homes were built with a hybrid system compared to the 2.63 million homes that used an all-electric heat pump or the 4.36 million homes that installed a gas furnace. Future studies could build on AGA's model and show the cost and environmental benefits of using a different fuel to meet the auxiliary load at more significant market penetrations than the current trend.

[4] American Gas Association, *Energy Insights November 2021, New Construction vs. Net Market Share Growth* *https://www.aga.org/globalassets/news--publications/fois/public/aga_energyinsight_nov21.pdf*

Calculating Appliance and Average Site Efficiency for Non-Space Heating Appliances in Residential and Commercial Buildings

In Table 1, we assume the following efficiencies for non-space heating appliances:

Table 1 – Assumed nameplate efficiency of residential and commercial end uses

End Use	Existing Gas Customers	Residental Baseline Scenario	Electrification Scenario	Existing Gas Customers	Commerical Baseline Scenario	Electrification Scenario
Space Heating	80%	96%	300%	80%	96%	300%
Water Heating	75%	82%	200%	75%	82%	125%
Cooking	40%	40%	75%	40%	40%	75%
Drying	384%	384%	393%	384%	384%	393%
Cooling	n/a	n/a	n/a	400%	400%	300%

For each city, the average non-space heating energy requirement reflects a mixture of end uses. An estimated average site efficiency for each scenario is needed to estimate the impact of baseline improvements to current gas customers or through electrification. The average site efficiency of current end-use is based on market shares developed from EIA's residential and commercial surveys (RECS 2015 and CBECS 2012) and the assumed current efficiency of gas water heaters, stoves, dryers, and commercial coolers.

In the baseline gas scenario, the water heater's efficiency was upgraded from 75% to 82% and would reflect a slightly better average site efficiency in our model. In the electrification scenario, all shares of gas appliances would be changed to all-electric options, with the biggest impact on site efficiency coming from a 200% efficient heat pump water heater replacement. Compared to residential customers, commercial customers overall see higher average efficiency for gas appliances because of cooling loads. Cooling or refrigeration loads are assumed to be more efficient for gas vs. electricity due to the considerable size of the units being deployed.

The consumption data shows variations between regions based on the reported mixture of appliances. For example, regions with more cooking relative to water heating report a lower overall efficiency. Of note, we did not evaluate the installation costs between gas and electric appliances for the commercial customer segment because commercial customers have widely diverging requirements for space heating capabilities.

Table 2 shows the site efficiency of residential and commercial non-space heating consumption by region.

Table 2 – Estimated average site efficiency of non-space heating equipment

Residential non-Space Heating Consumption

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain North	Mountain South	Pacific
Existing Gas Appliances	68%	65%	69%	71%	62%	54%	61%	69%	68%	64%
Electrified with Heat Pump	168%	155%	165%	179%	154%	133%	150%	178%	165%	155%
Improved Gas Appliances	74%	70%	74%	77%	67%	58%	66%	75%	74%	69%

Commerical non-Space Heating Consumption

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Existing Gas Appliances	83%	89%	73%	66%	69%	64%	65%	65%	75%
Electrified with Heat Pump	145%	151%	140%	135%	128%	126%	131%	123%	144%
Improved Gas Appliances	93%	100%	79%	71%	73%	68%	69%	69%	83%

Calculating Installation Costs of New Builds and Conversions by Fuel Type

For purposes of our analysis, the baseline gas scenario assumes that current gas homes and businesses would continue to use natural gas and make efficiency upgrades as furnaces and water heaters are replaced. In the electrification scenario, all homes and businesses using natural gas must upgrade to a heat pump furnace and water heater, regardless of the age or type of building. Equipment and installation costs were derived from the ICF "Implications of Policy-Driven Residential Electrification" 2018 Report. Costs represent a national average to replace or install a new unit in either scenario explored.

For older homes built before 1960,[5] households would require additional upgrades, and the equipment costs for choosing electrification would also be higher than new gas or new electric homes. Table 3 describes this input data for the residential sector. Costs are divided between the "equipment costs" for the physical equipment, and "installation costs" for the labor associated with setting them up. Replacing existing gas equipment at average fleet efficiency with new, high-efficiency gas equipment would save on energy costs but requires additional equipment and installation costs.

Table 3 – Input costs and assumptions for residential conversions (2018 $)

Type of Equipment	Equipment Costs	Installation Costs
High-Efficiency Gas	$4,788	$1,903
Electrification	$4,158	$2,224
Electrification (older homes)	$7,918[5]	$2,224[5]

Older homes may require additional electrical upgrades to allow for a cold climate heat pump and a water heater. The total average cost of upgrading older housing units was estimated to be $3,530 for each unit.[6] AGA's estimates for these upgrades only include the cost of equipment for a new electrical panel (200 Amp

[5] US Census Bureau, American Housing Survey 2019, Based on total number of homes reported in each MSA built before 1960 with a natural gas furnace.
[6] Based on average single and multifamily cost of upgrading electrical panel and branch circuit in the 2019 City of Palo Alto Title 24 Energy Reach Code Cost Effectiveness Analysis

Upgrade) and branch circuit (15 Amp to 30 Amp). Additional costs associated with ductwork and labor were not included.

Modeling Impacts on the Economy

AGA engaged FTI Consulting to examine the potential impacts to the local economy from converting residential and commercial building stocks of each city from natural gas to electricity. FTI used AGA's model results to simulate the economic impact of electrification (more demand for electricity, less demand for gas, and higher installation costs) with the help of the IMPLAN policy model. IMPLAN is a widely applied model for answering questions on impacts from policy changes. Appendix A shows a diagram for how IMPLAN works. The inputs and results of the IMPLAN model represent the net difference between the baseline and the electrification scenarios through 2040.

AGA's inputs into the IMPLAN model takes the form of six categories for residential and commercial customers.

1. Equipment Spending
2. Installation Spending
3. Maintenance Spending
4. Natural Gas Spending
5. Electricity Spending
6. Consumption Reallocation

The category "Consumption Reallocation" is the opportunity cost of energy utility service. In other words, consumption reallocation refers to the disposable income unavailable to consumers due to the higher energy-related costs associated with each scenario. Energy is a basic need, making energy demand highly inelastic. Thus, customers reallocate their spending away from personal or business needs for goods and services at the margin when confronted with higher energy-related costs.

The model shows that a common economic impact of electrification is the negative effect that the reallocation imposes on other sectors such as retail, healthcare, food services, and arts and entertainment. The reduced demand for the goods and services provided by these sectors reduces the total hours of labor and wages, resulting in a measurable net loss in jobs and personal income.

Modeling and Estimating Local Emissions

AGA's model utilizes the National Renewable Energy Laboratory's ReEDS model to estimate the potential emissions impact from local electrification. ReEDS produces a least-cost solution of the U.S. electric sector under given modeled constraints and therefore can project structural changes given a set of inputs such as fuel costs, technology costs, and policies. The model starts each year with representations of existing generation capacity to meet demand at the lowest cost. Historical demand is broken up by 134 sub-regions of the lower 48 states and the District of Columbia. ReEDS also offers additional representations of end-use demand for each of the four seasons and for four different times of the day.

Our analysis considers some critical limitations of the ReEDS model. Specifically, ReEDS relies on a single weather year, and does not adequately account for heat pump performance during peak winter conditions.

Energy demand increases as outdoor temperatures drop and varies substantially over monthly, daily, and hourly periods. For example, in many parts of the U.S., the month of January may account for 20% or more of annual gas space heating costs.[7] The average seasonal conditions reflected in the ReEDS weather inputs do not reflect the coldest week, day, or hour in a particular year. Because the efficiency of a heat pump is dependent on the outdoor air temperature, the use of electric equipment is likely to result in substantially higher electricity demand loads at certain times of the year than the seasonal average presented by the ReEDS model.

In 2020, NREL made the Cambium database available to the public. The Cambium database contains hourly cost data that is obtained by running the ReEDS model through PLEXOS. This commercial production cost model can simulate the least-cost hourly dispatch of generation capacity with a more detailed set of nodes and transmission lines. The model incorporates unit-commitment decisions, explicit operating constraints (e.g., maximum ramp rates and minimum generation levels), and operating reserves. Of note, PLEXOS can be run with nested receding horizon planning periods (e.g., day-ahead and real-time) to simulate realistic electric system operations.

To use the PLEXOS model, NREL converted the results of the ReEDS model to fit the nodal and hourly characteristics of PLEXOS. NREL expanded the seasonal end-use demand load assumptions to fit an hourly model extending to year-round modeling as part of the conversion process. Thus, using the data from the Cambium database in connection with our local electrification model, this analysis can find hourly estimated values for long-term emissions from marginal demand and wholesale cost of power generation.[8]

Conclusions from AGA Emissions Modeling and Cambium Database

AGA's approach for modeling emissions relied on developing a 10-year average hourly space heating demand for each city and connecting each hour to the hourly long-term marginal rate of emissions taken from the Cambium database. Hourly heating energy requirements were generated by allocating the monthly estimated heating energy demand by hourly heating degree data.[9] The following subsections describe some of the results of the modeling.

[7] AGA FOIS: Estimated Winter Heating Costs by Fuel Type, https://www.aga.org/globalassets/news--publications/fois/public/fois-2020--10-winter-heating-costs-by-furnace-type.pdf

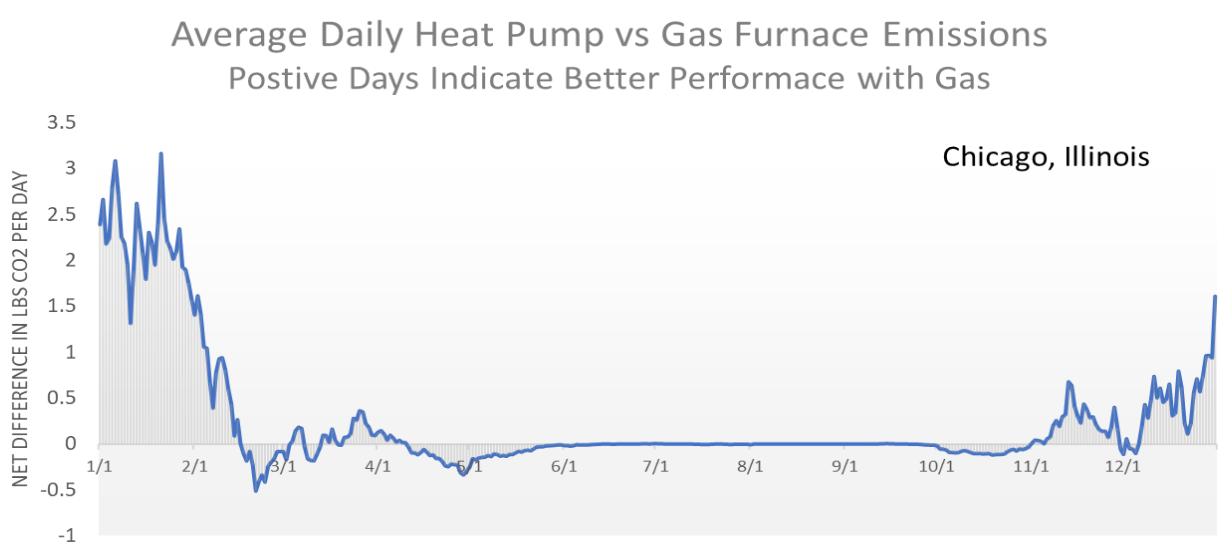
[8] There is one minor area of potential improvement in our methodology. Our electrification model based the performance of heat pumps on the last 10 years of weather data and PLEXOS uses weather data that starts in 2012. The 2012 winter heating season was amongst the warmest compared to the 30-year average in the last decade (2012 had a national heating degree day or "HDD" value of 4144 vs. the 30-year HDD average of 4734[8]). As a result, estimates for long-term marginal capacity may reflect a larger share of new renewable capacity than what might be observed during the winter peak of peak conditions. Further modeling should be conducted beyond the scope of the AGA model and the Cambium database to properly account for long-term normal winter weather and peak of peak conditions.

[9] National Centers for Environmental Information, https://www.ncdc.noaa.gov

Space Heating

The model for space heating consumption resulted in higher usage and lower overall heat pump efficiency during the late and early hours of the day when the outdoor air temperature is most likely to approximate the seasonal low. Using Chicago as an example, during the coldest days of the year, gas furnaces would have reduced CO_2 emissions by at least 60%. Based on the most recent 2020 "low cost of renewables" long-term marginal emission rate, the gas furnace outperformed the heat pump by reducing emissions by 18%. Importantly, the 20-30 year analysis accounts for a downward trend in the long-term marginal emission rate estimated by NREL. Figure 4 shows an example the relative average daily emissions in Chicago over an entire year.

Figure 4 – Average daily heat pump vs gas furnace emissions in Chicago IL



Regional Conclusions

The finished model, coupled with NREL and EIA's resources, provides an indication of the best-case scenario for emissions, life cycle costs, and peak demand. The results demonstrate a "best-case" outcome, because, as described above, the model only contemplates using high-efficiency cold climate heat pump adoption.

The total impact of electrification on individual regions varies and is gradual as every residential and commercial customer is incrementally electrified over a few decades. Only relative changes to total end-use demand can be estimated to show the potential impact on all-electric power customers.

Under this "best-case" scenario, some modeled cities show the potential for some emissions savings along with potentially higher costs based on current commodity price forecasts, while other cities show increasing costs and emissions.

Costs not included in the analysis

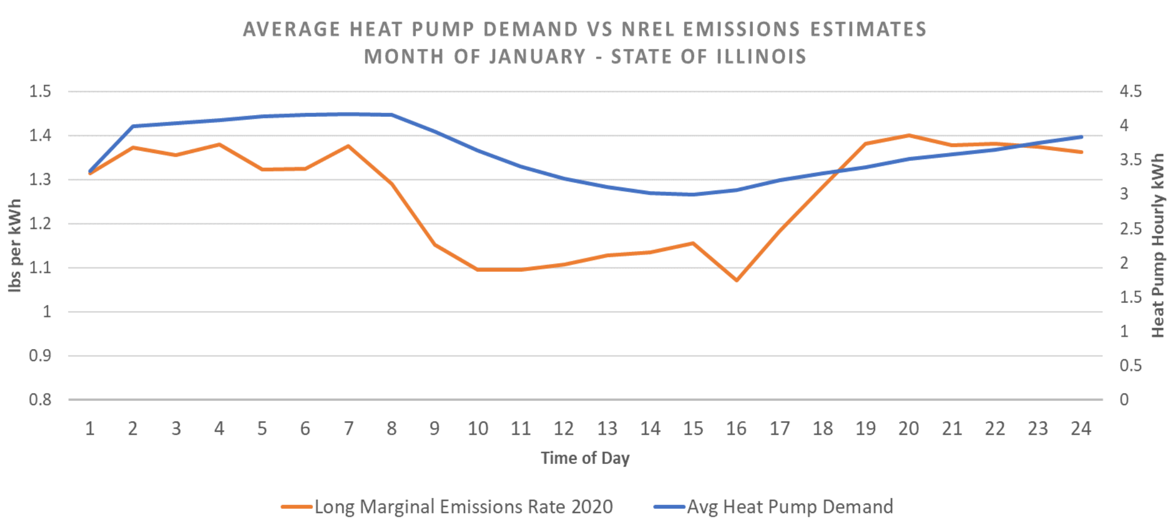
The costs presented in this analysis do not include all the costs associated with a mandated electrification policy. Other considerations include:

- Electric generation, transmission, and distribution system upgrades required to meet increased electric end-uses and peak energy demands in the residential, commercial building sector.
- Possible effects on energy system reliability or resilience.
- Potential costs associated with rate increases to natural gas utility customers as fixed system costs are applied to a smaller customer base.
- Changes in natural gas commodity prices associated with lower natural gas demand.
- Alternative fuels, and costs associated with fuels to support a lower carbon natural gas distribution system.

Time Sensitivity

A review of the average peak of peak consumption and hourly long-term marginal rate for emissions shows that emissions are highest in the coldest hours of winter nights when space heating is needed most. Demands at those times might be considerably higher than peak summer electric demands.

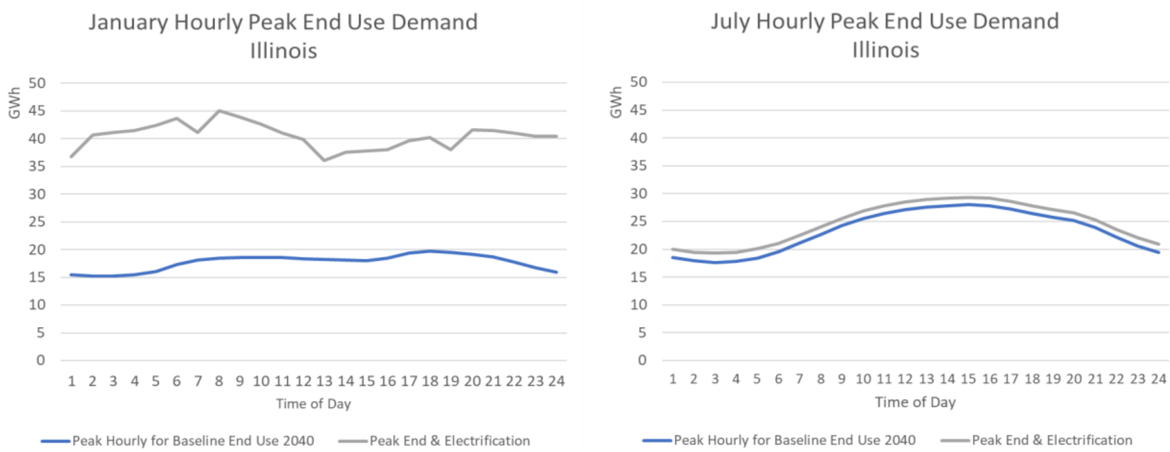
Figure 5 – Average hour heat pump energy usage in January vs long term marginal rate



The peak end-use for all power generation would shift to the winter nights in every city evaluated. A mandated electrification policy may have implications for new renewable capacity, especially solar and short-term grid battery supply, to meet peak electricity demand. Figure 5 compares the average hourly 2020 "low cost renewables" long term marginal rate from NREL with AGA's modeled heat pump demand for the month of January.

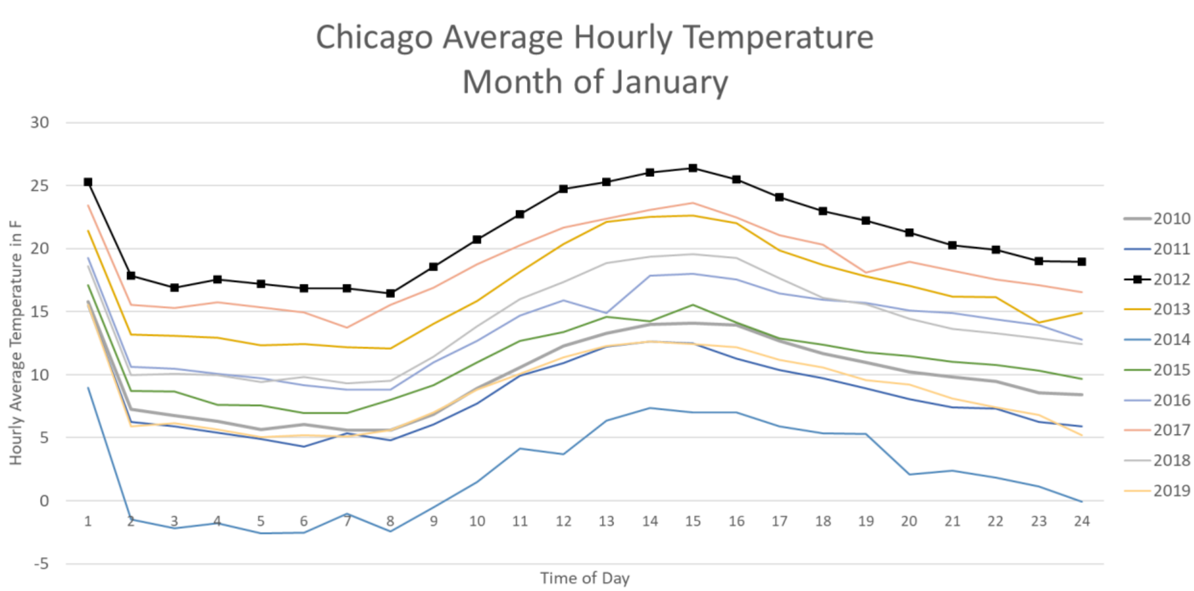
Figure 6 compares peak end-use demand in Illinois in the summer and the winter under the baseline and policy mandated electrification scenarios in 2040. Both scenarios were built on the NREL's cambium database forecast for 2040 electricity demand which only relies on 2012 weather data. Peak electricity demand increases more severely under a 10-year "peak of peak" event. The implications of this type of strain on energy systems may have an impact for overall energy system resilience. Nonetheless, additional margins, lower appliance efficiencies, and a 30-year horizon for weather events can be factored into account for a broader range of possibilities.

Figure 6 – Peak of peak January demand for Illinois in 2040 after electrification policy



Finally, since NREL utilized a single base year to predict the impact of weather, the degree to which that year is too warm or too cold will impact the results shown at peak of peak times of the year. Our model helps define the demand side requirements of electrification, but the year used by NREL to estimate emissions could underestimate the impact of a peak winter event for many parts of the country. As discussed before, NREL used 2012, a relatively warm year, as the baseline. Figure 7 shows that 2012 was the warmest year in Chicago between 2010 and 2019. Even in a warm year, our model predicts a shift from a summer peaking electric system to a winter peaking one under electrification. Had NREL used a different baseline year, the results would have likely been even more pronounced.

Figure 7 – Average hourly temperature in Chicago IL during January



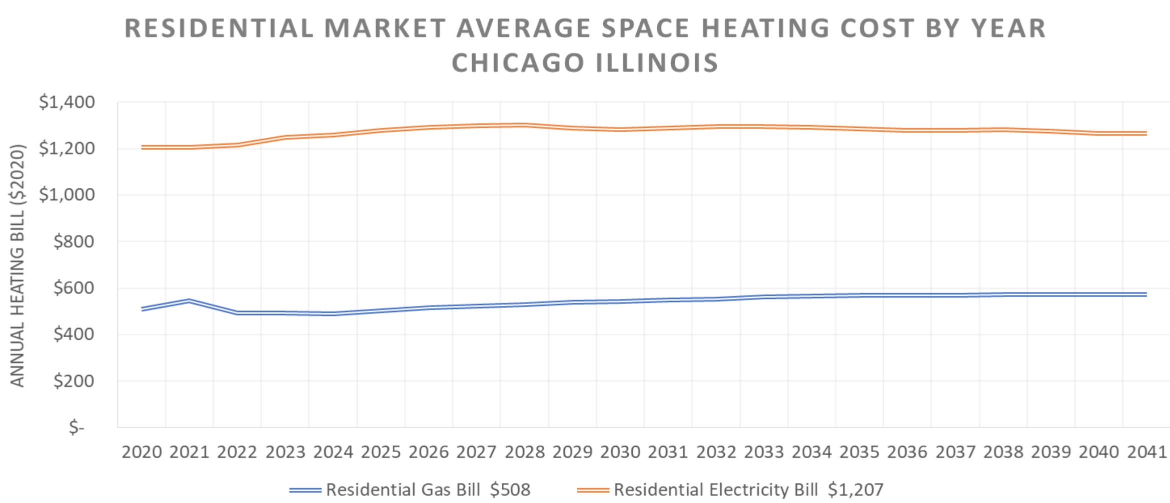
Modeling First Year and Annual Energy Costs

First-year average energy costs for the baseline and electrification scenarios were based on EIA's 2019 monthly residential and commercial commodity pricing. To account for real future changes in energy prices, the model uses data from the EIA's Annual Energy Outlook (2021) to factor in the percent change in prices through 2050. AEO for energy price projections were used to ensure consistent data sourcing between our model and the ReEDS model. However, there are regional and seasonal limitations to the AEO forecast that require additional inputs.

Because space heating takes place at specific times of the day and tends to focus on specific months of the year, the cost of electricity for heat pump customers can be refined using an hourly cost estimate. The 2021 AEO includes an electric market module regional forecast of generation, transmission, and distribution costs through 2050. Using the simulated wholesale cost of energy taken from the Cambium database, a new forecast for generation costs was used to estimate the actual cost of operating a heat pump or non-space heating appliance during winter months. Natural gas prices for space heating were assumed to be already priced into the EIA historical monthly and AEO 2021 forecast data. It currently accounts for 67% and 60% of all residential and commercial gas consumption[10].

Figure 8 shows an example the average annual cost to heat a home using 96% high efficiency natural gas furnace in the baseline gas scenario compared to the use of a 300% efficient heat pump in the electrification scenario.

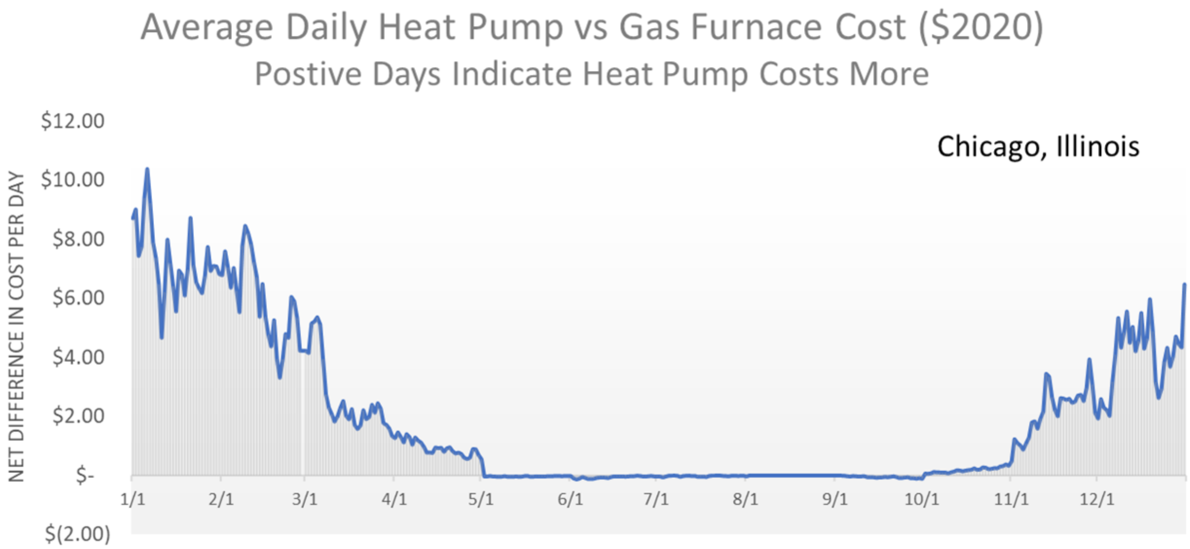
Figure 8 – Average annual space heating cost in Chicago IL for baseline and electrification scenarios



Reviewing the results of our cost analysis, in each scenario examined, the cost of operating a cold climate heat pump was higher than a high-efficiency gas furnace. Chicago and Denver had the most significant impact on customers, with heat pumps costing consumers between 135% and 138% more per year over the entire 20-year lifespan of the furnace. Other cities saw their 20-year lifecycle costs increase by 38% to 55% per year. Figure 9 shows an example the relative average daily costs in Chicago over an entire year.

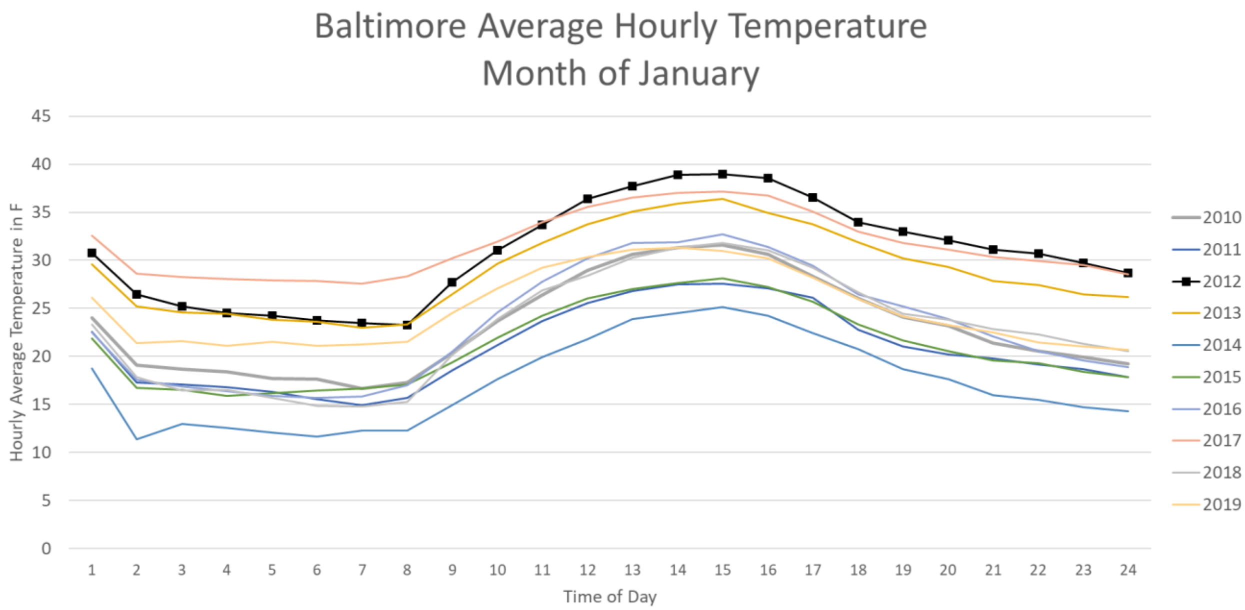
[10] See footnotes 2 and 3 for original EIA source

Figure 9 – Average daily heat pump vs gas furnace costs in Chicago, IL

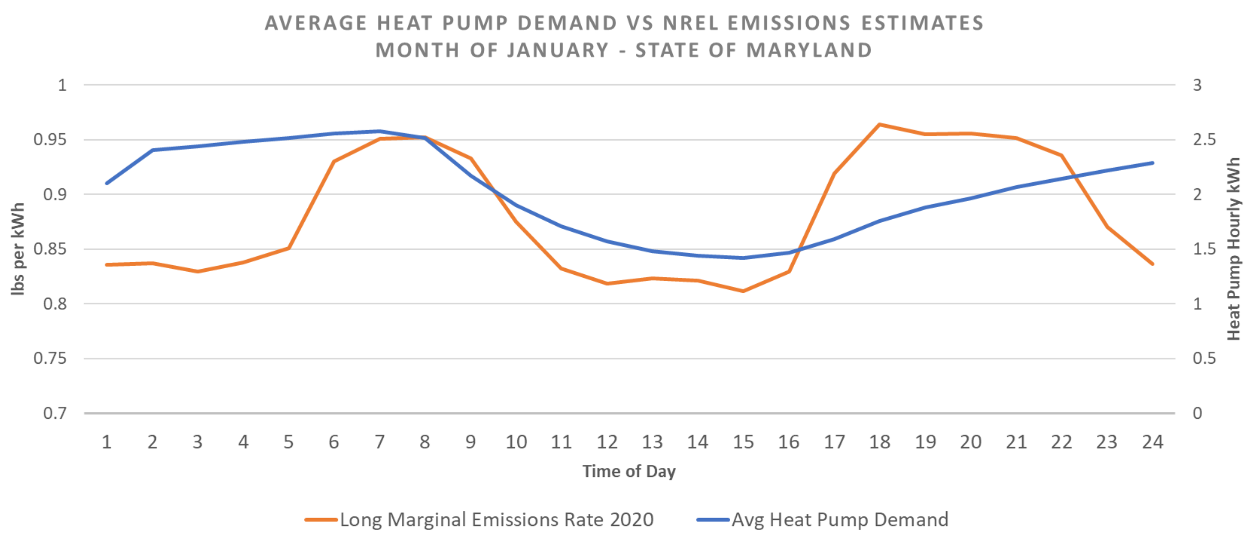


Appendix A: Baltimore, Maryland Charts

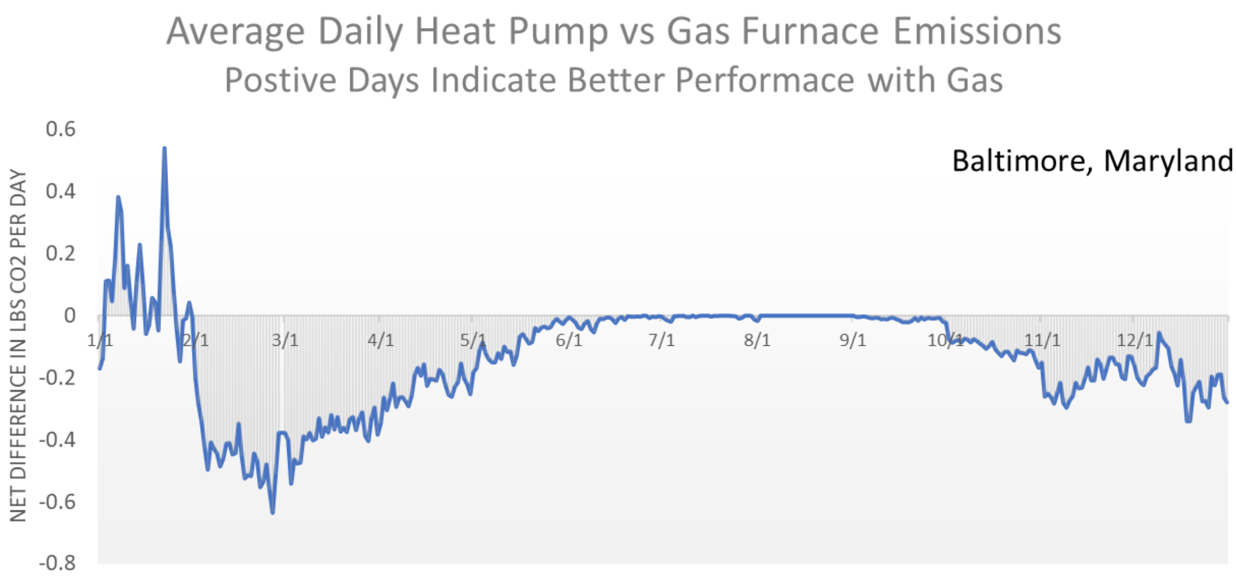
January Average Temperatures in Fahrenheit by Year 2010 – 2019



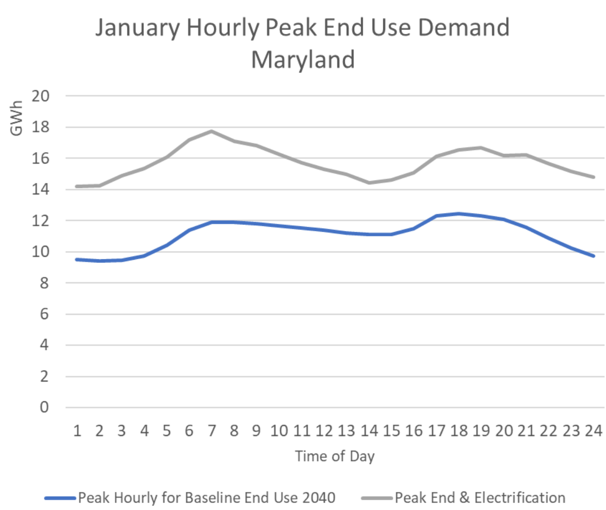
January Hourly Heat Pump Performance compared to Long Term Marginal Emissions Rate

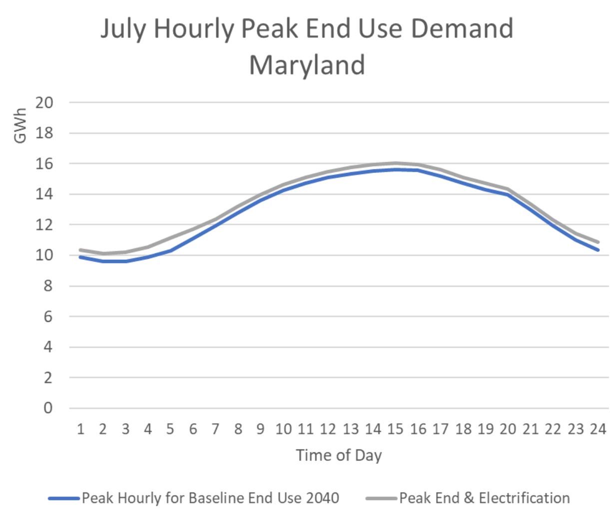


Daily Average Net Emissions for a Gas Furnace and a Cold Climate Heat Pump

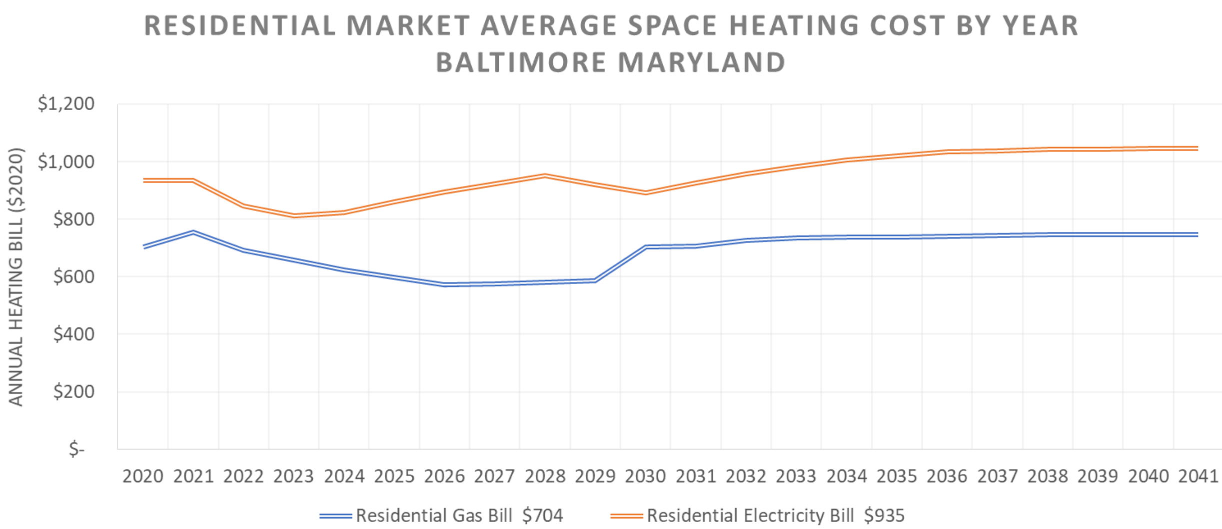


State Level Winter versus Summer Peak Electric Power End Use Demand

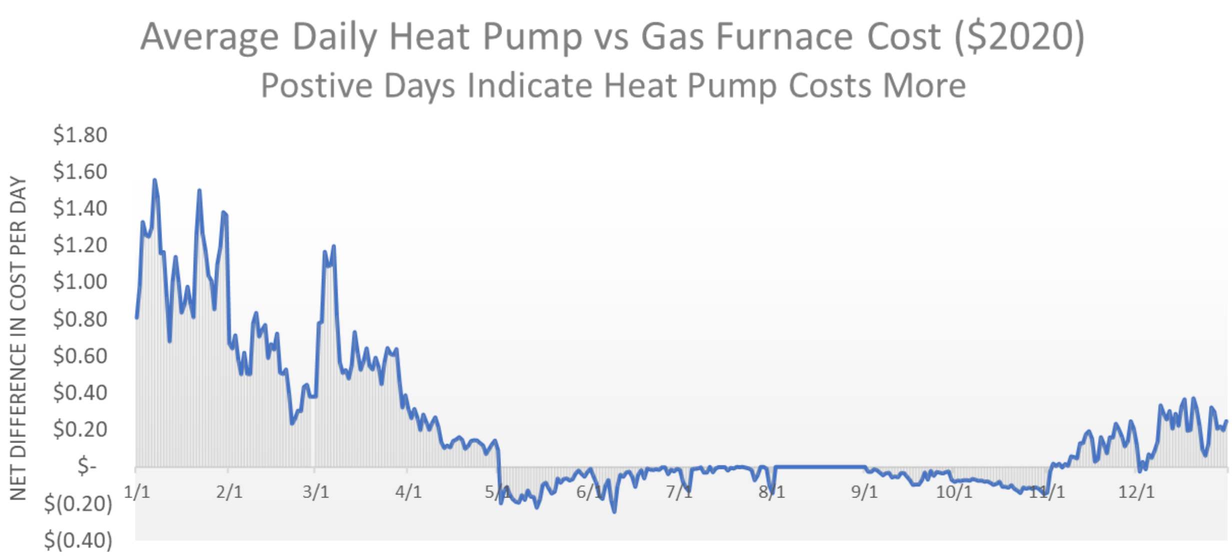




Annual Average Cost Difference for Gas Furnace and Cold Climate Heat Pump 2020 – 2041

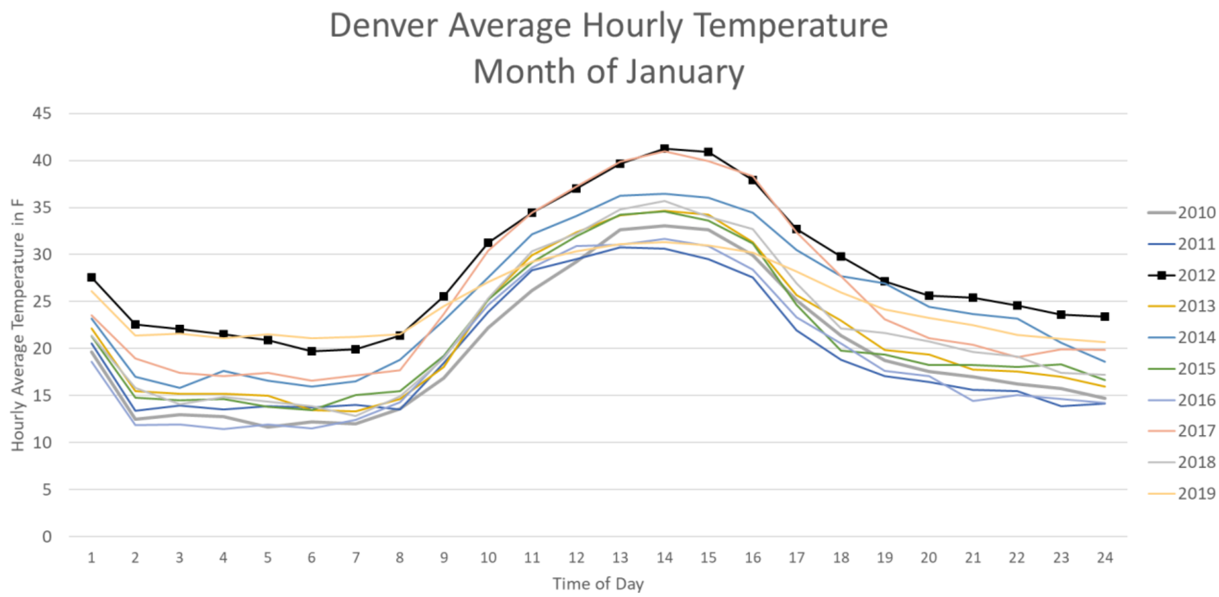


Daily Average Net Cost for a Gas Furnace and a Cold Climate Heat Pump

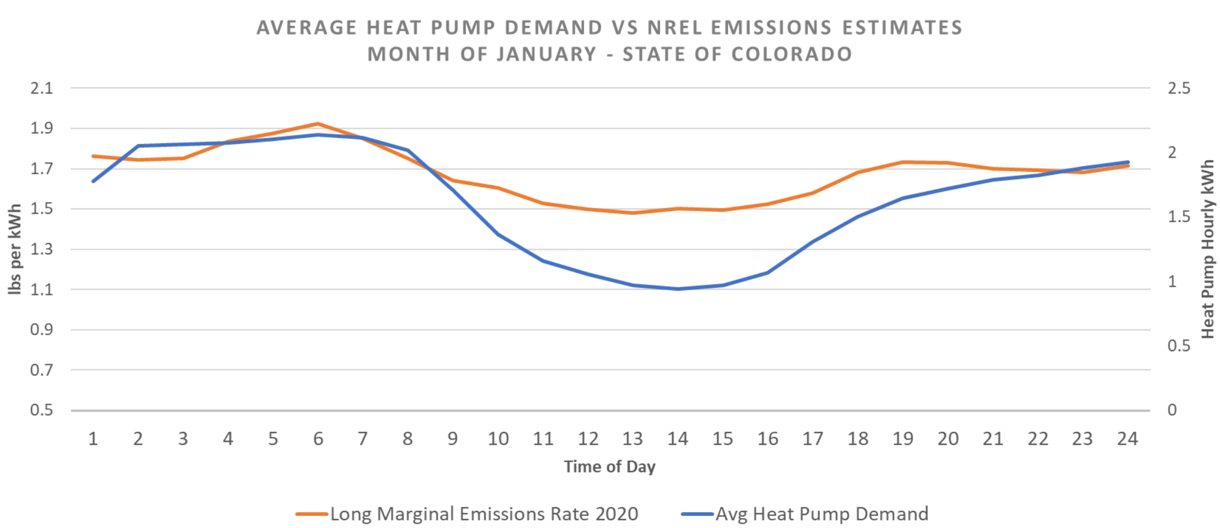


Appendix B: Denver, Colorado Charts

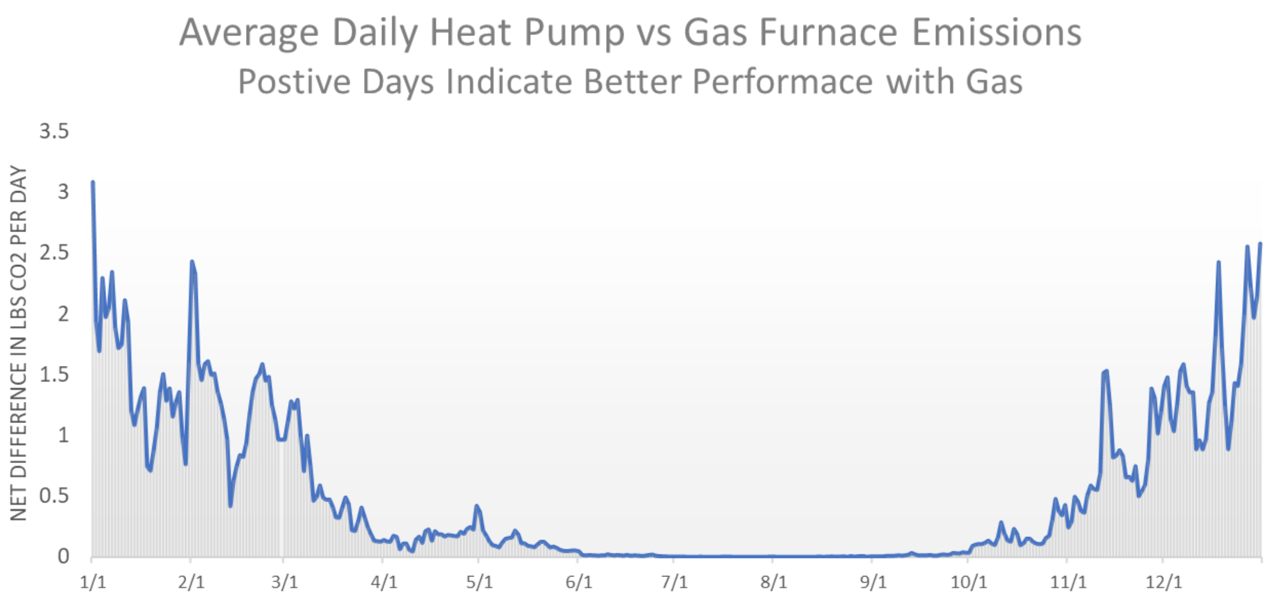
January Temperature in Fahrenheit by Year 2010 – 2019



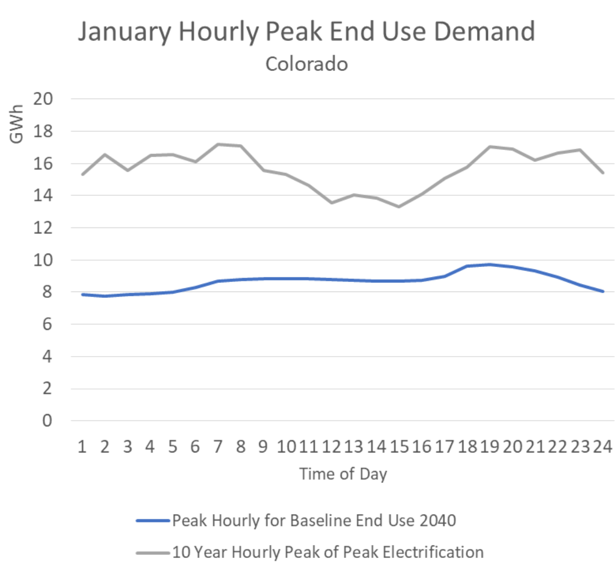
January Hourly Heat Pump Performance compared to Long Term Marginal Emissions Rate

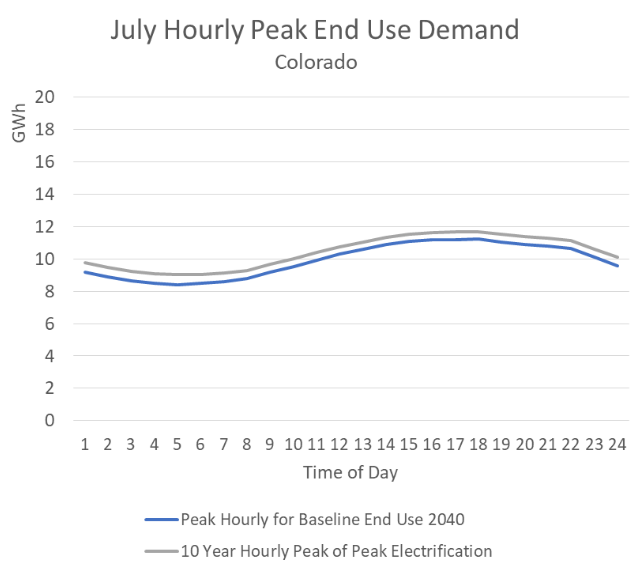


Daily Average Net Emissions for a Gas Furnace and a Cold Climate Heat Pump

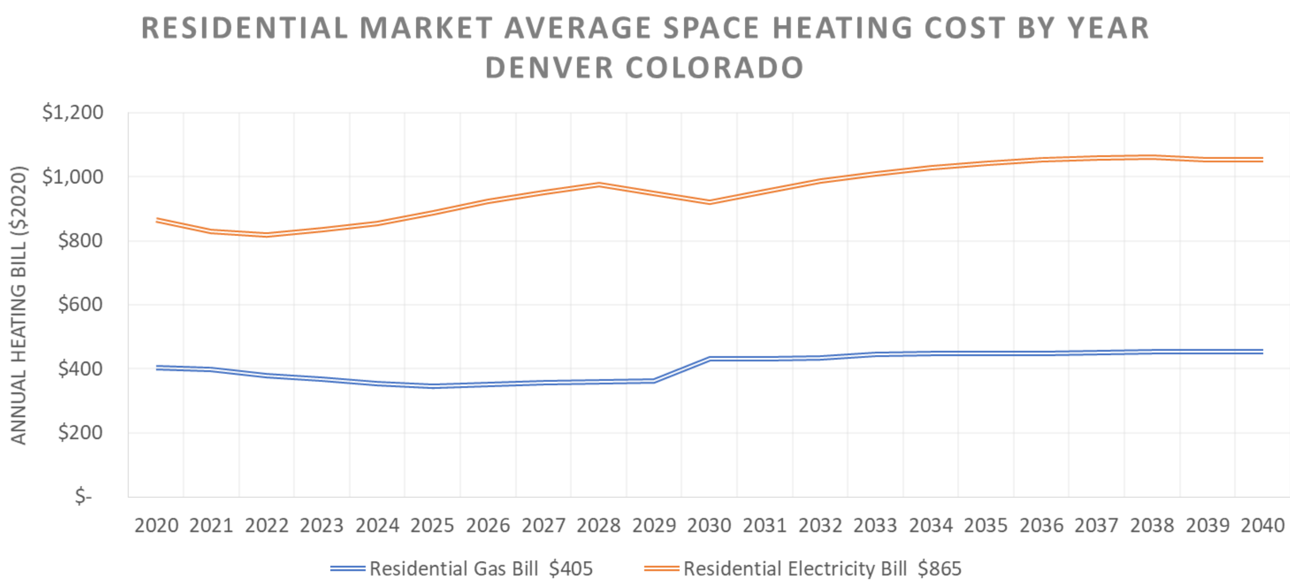


State Level Winter versus Summer Peak Electric Power End Use Demand

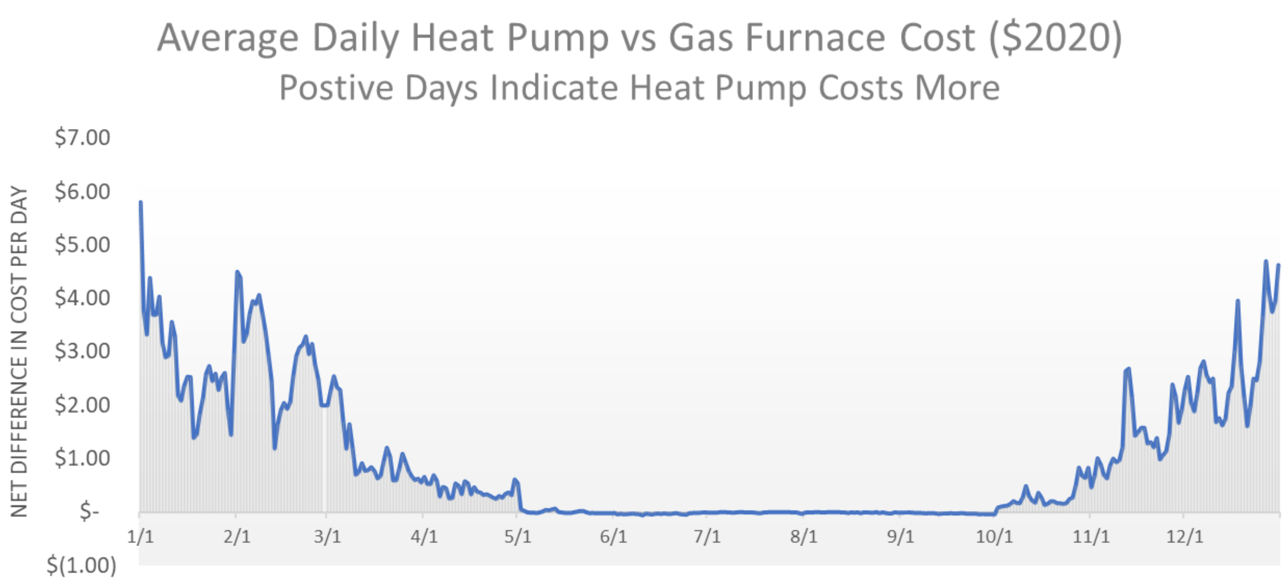




Annual Average Cost Difference for Gas Furnace and Cold Climate Heat Pump 2020 – 2041

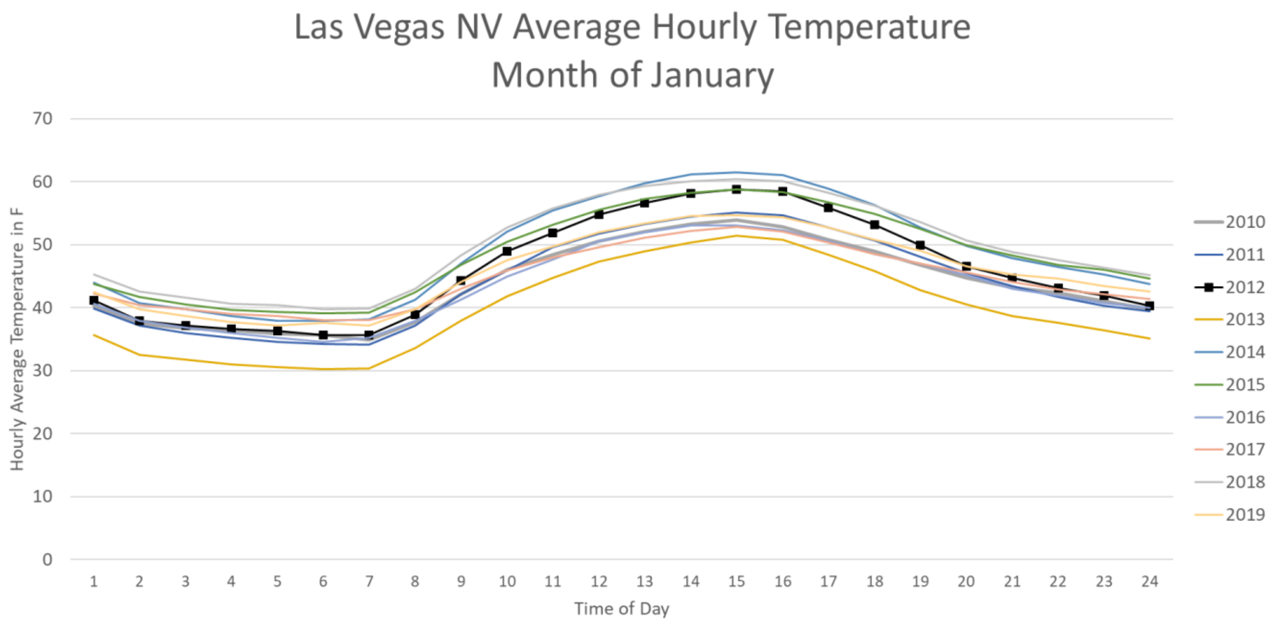


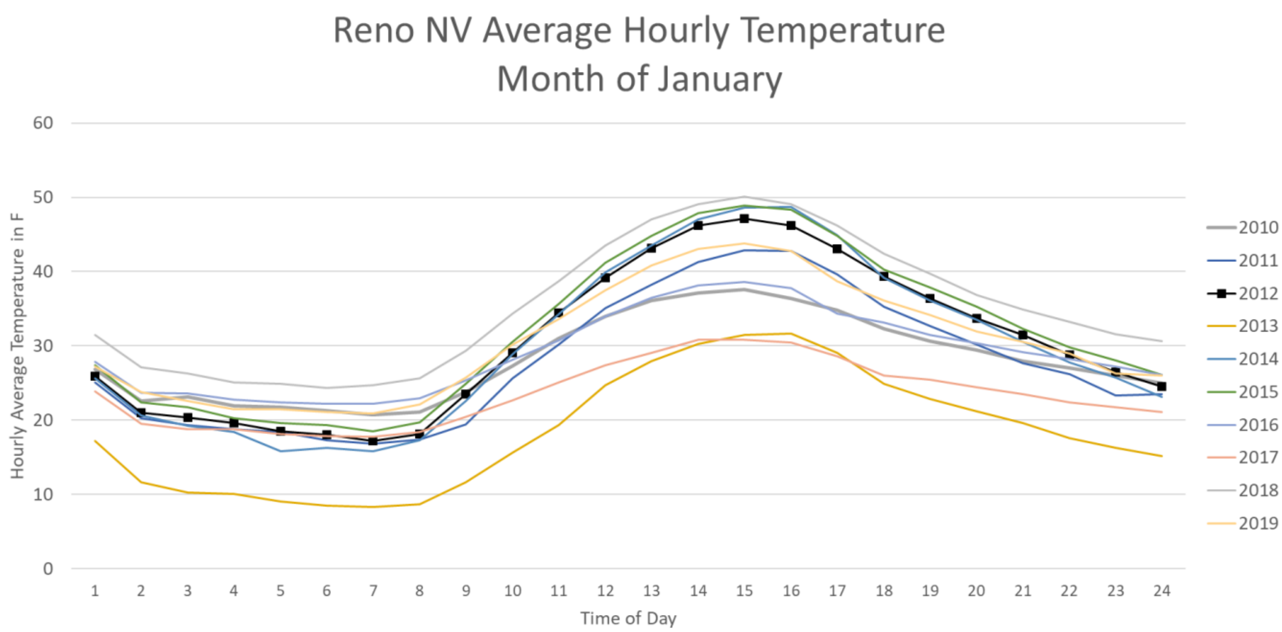
Daily Average Net Cost for a Gas Furnace and a Cold Climate Heat Pump



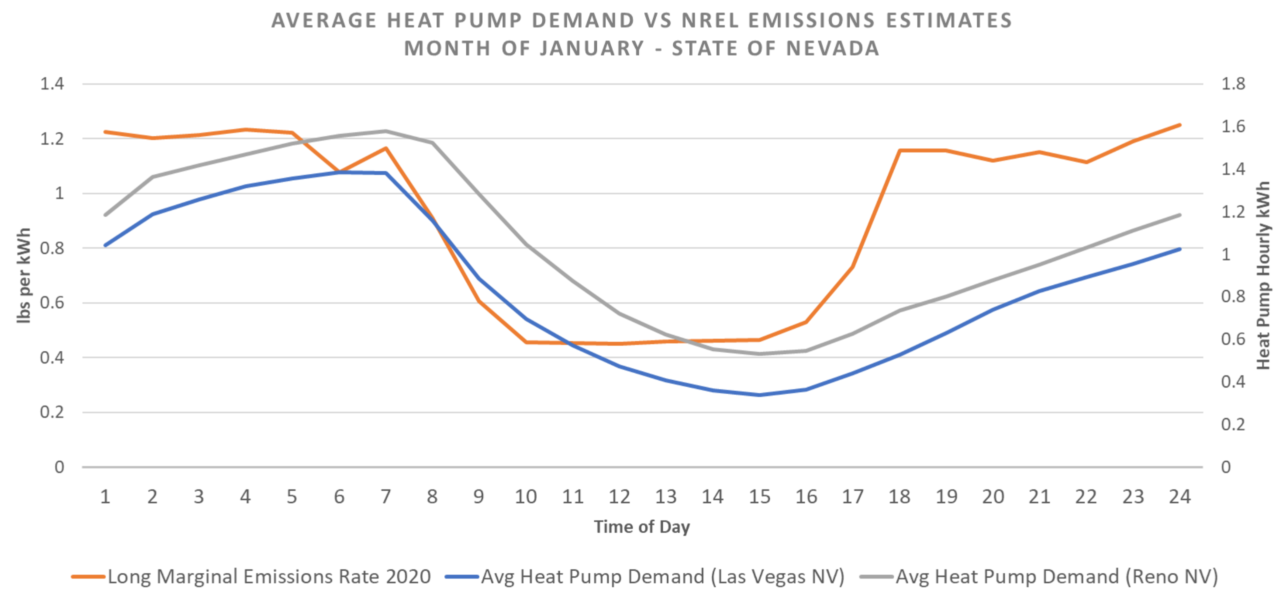
Appendix C: Las Vegas and Reno, Nevada Charts

January Temperature in Fahrenheit by Year 2010 – 2019

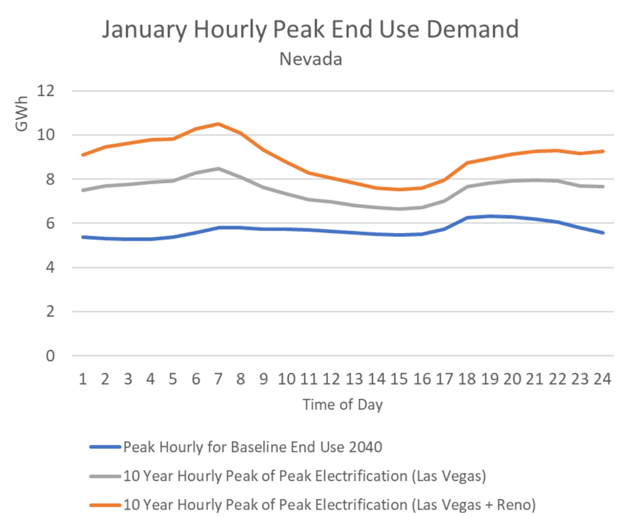


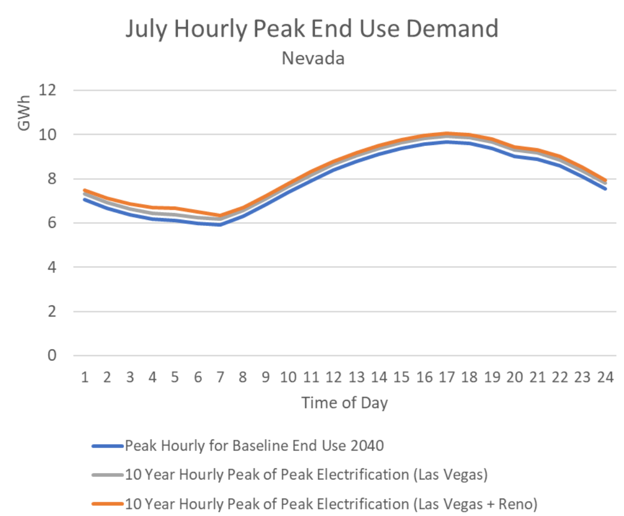


January Hourly Heat Pump Performance compared to Long Term Marginal Emissions Rate

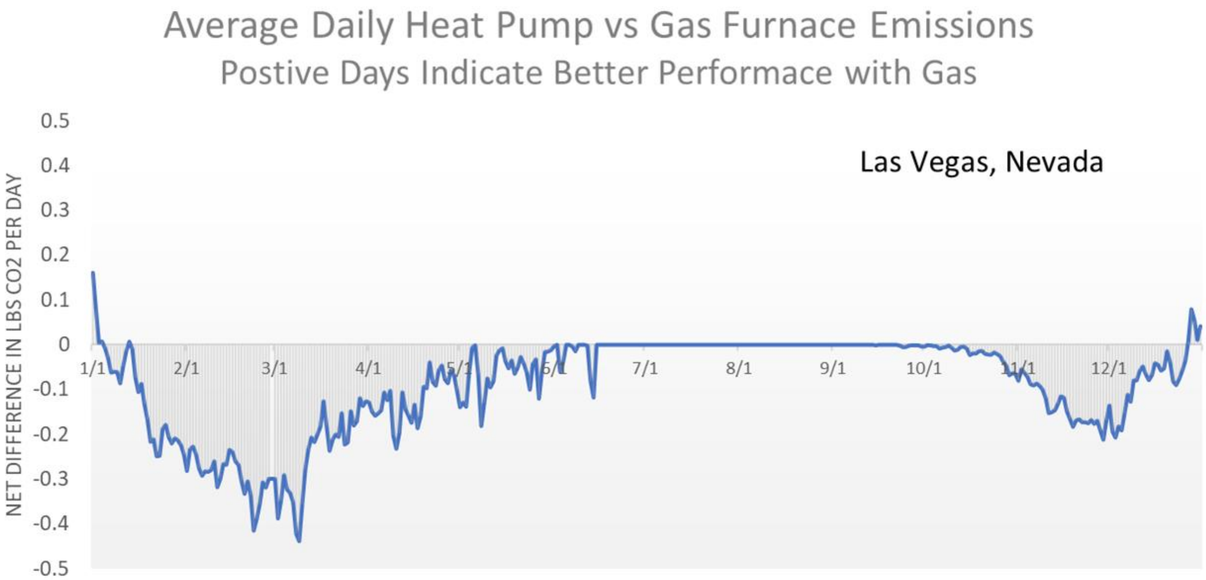


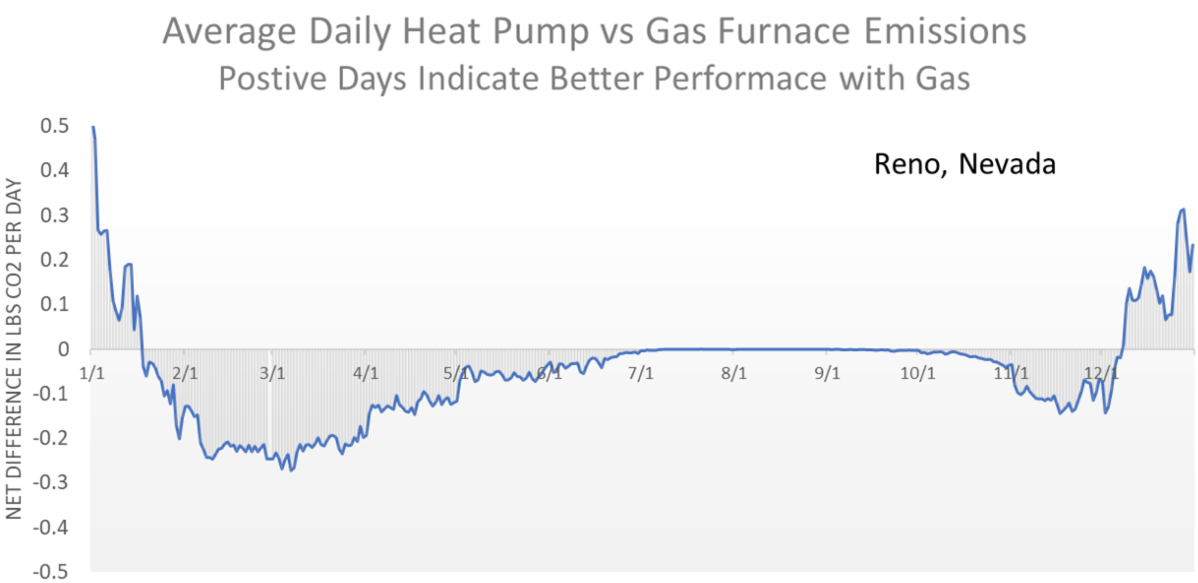
State Level Winter versus Summer Peak Electric Power End Use Demand



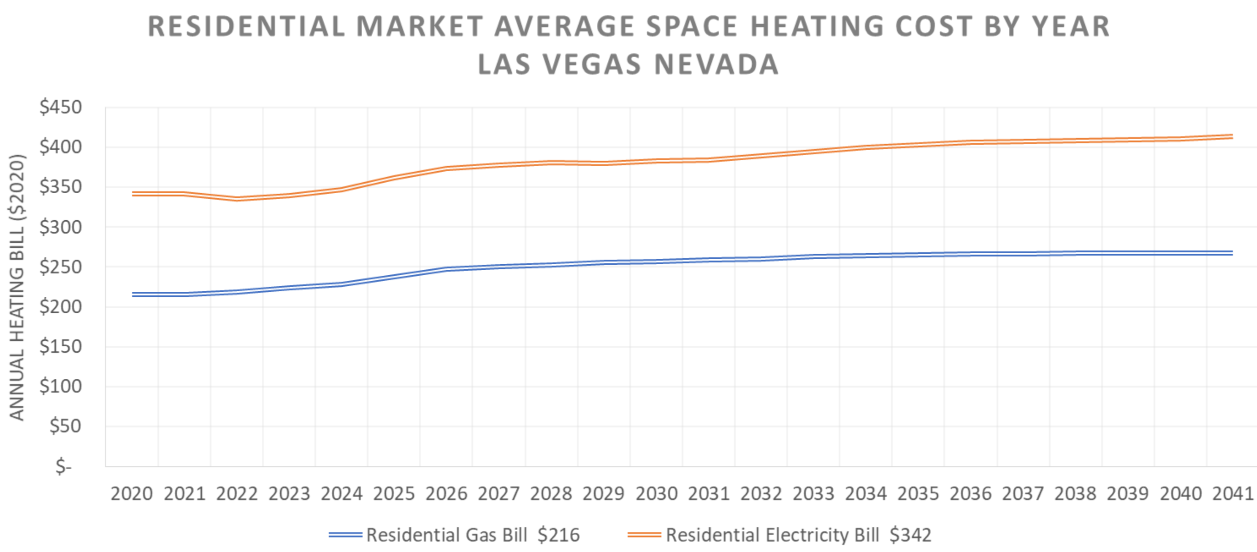


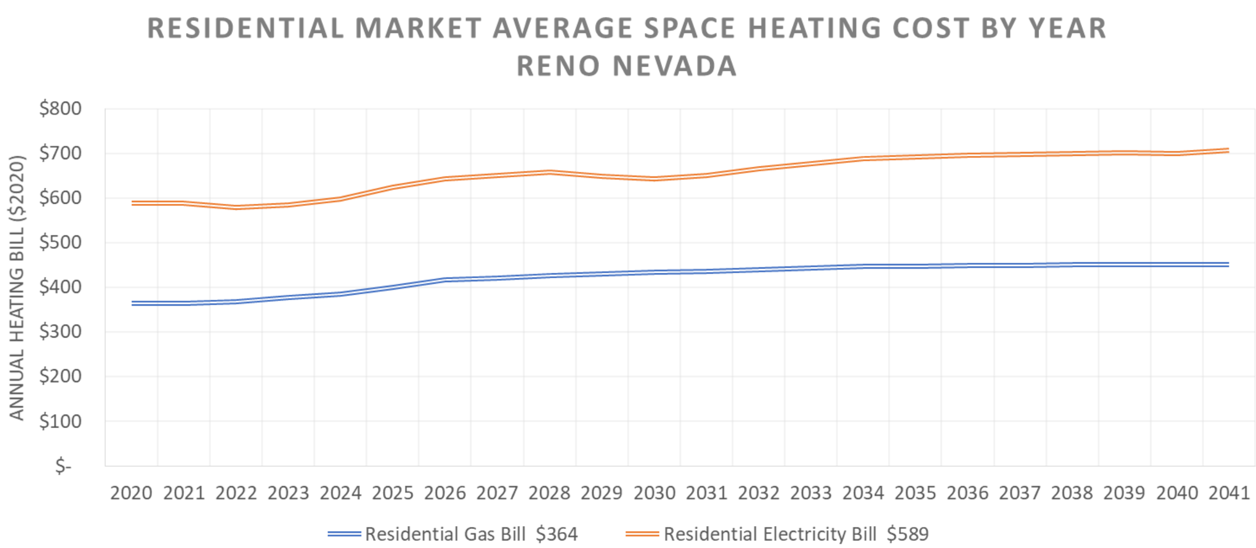
Daily Average Net Emissions for a Gas Furnace and a Cold Climate Heat Pump



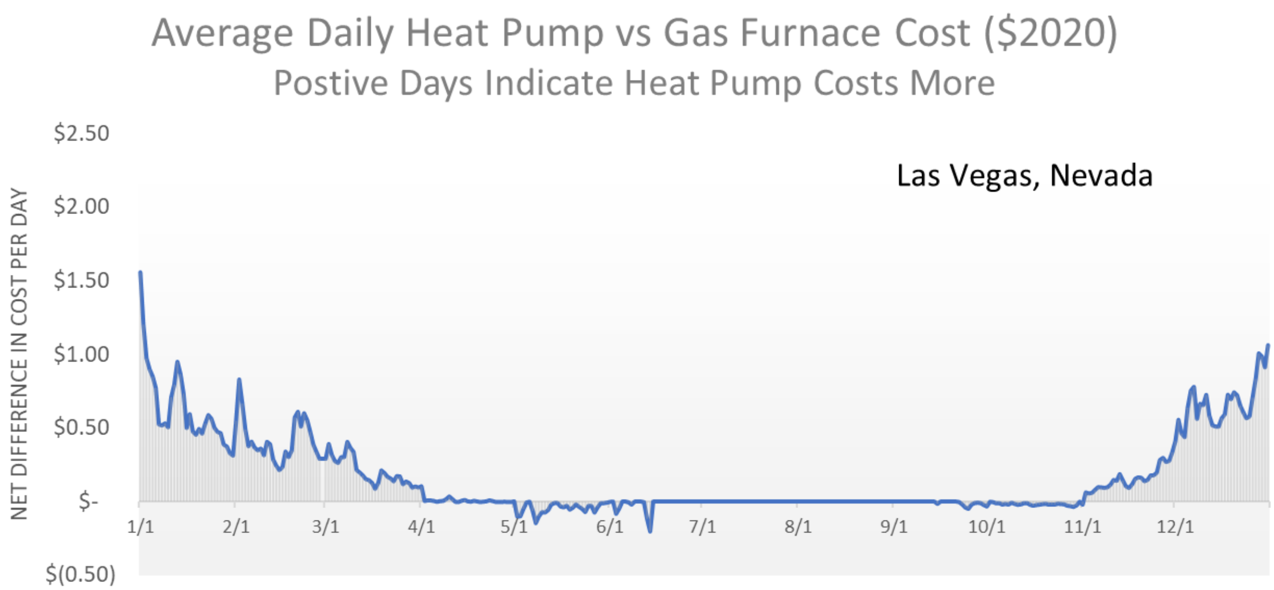


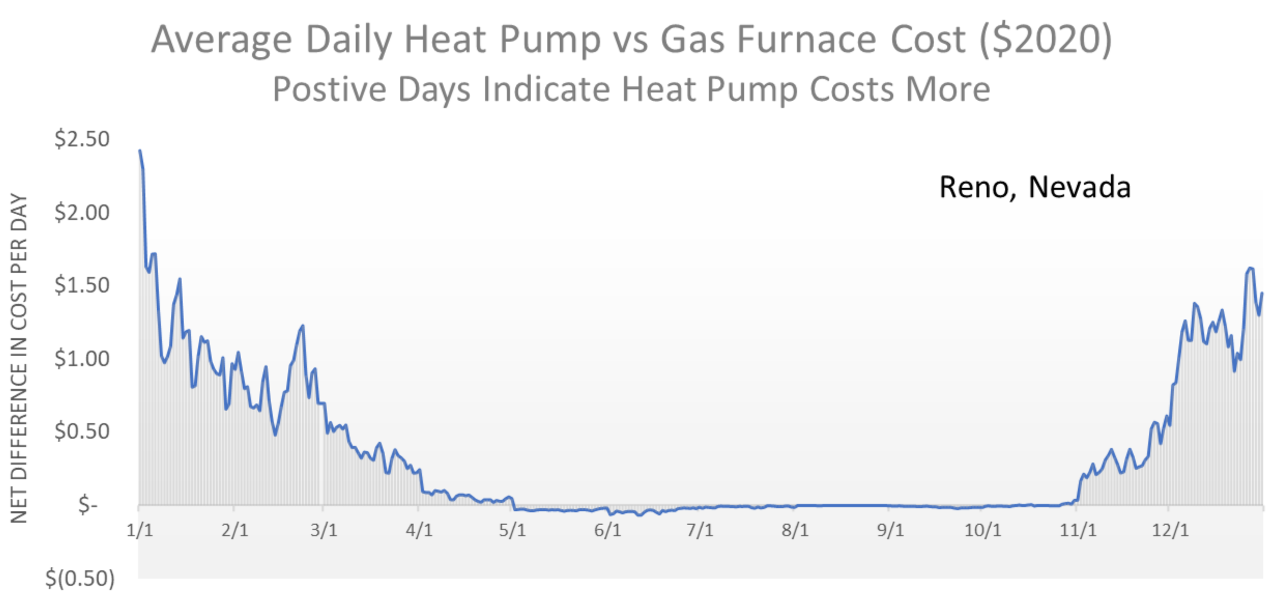
Annual Average Cost Difference for Gas Furnace and Cold Climate Heat Pump 2020 – 2041





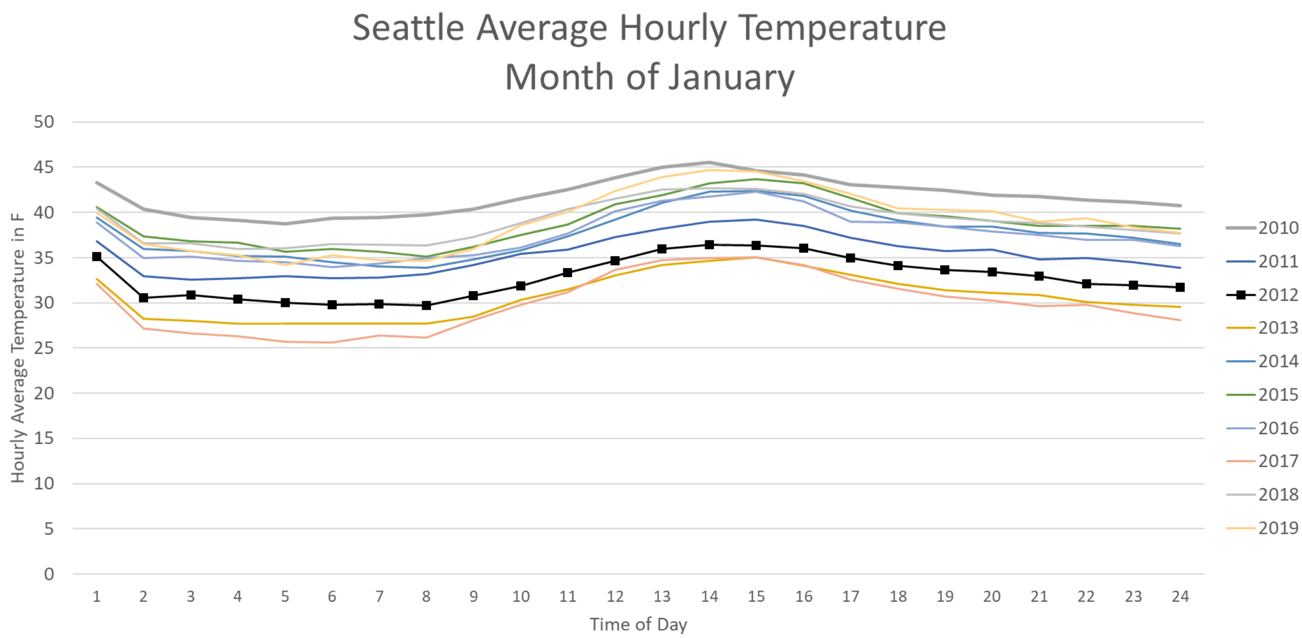
Daily Average Net Cost for a Gas Furnace and a Cold Climate Heat Pump



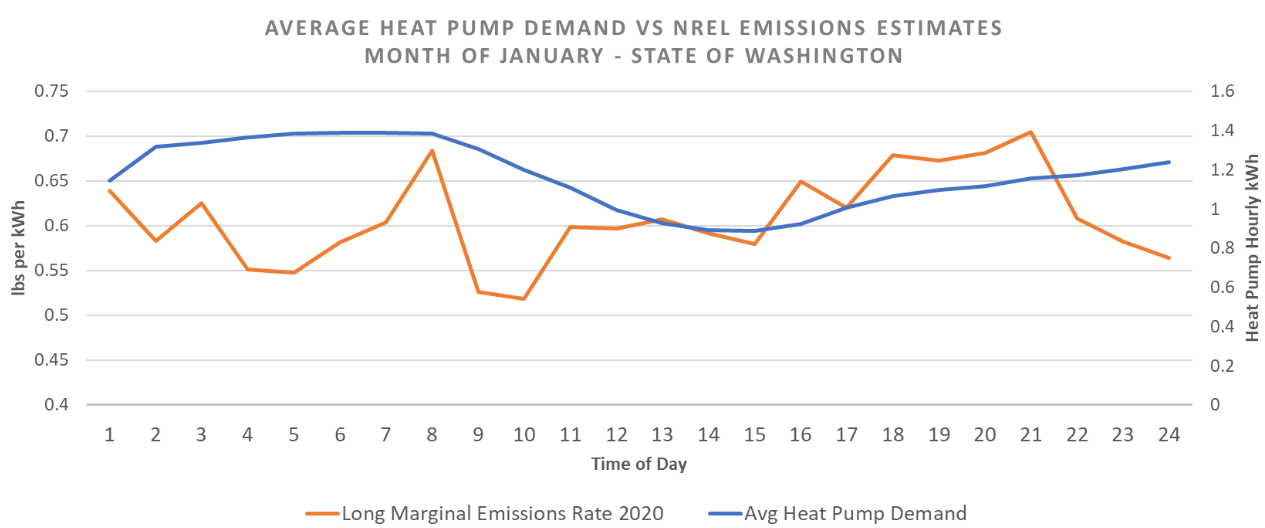


Appendix D: Seattle Washington Charts

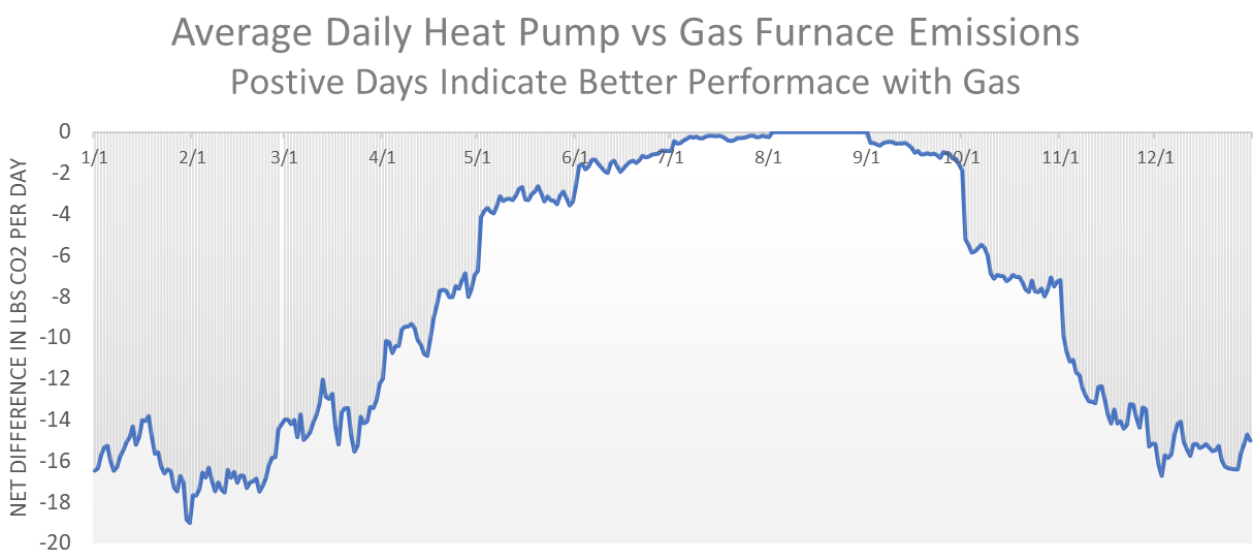
January Temperature in Fahrenheit by Year 2010 – 2019



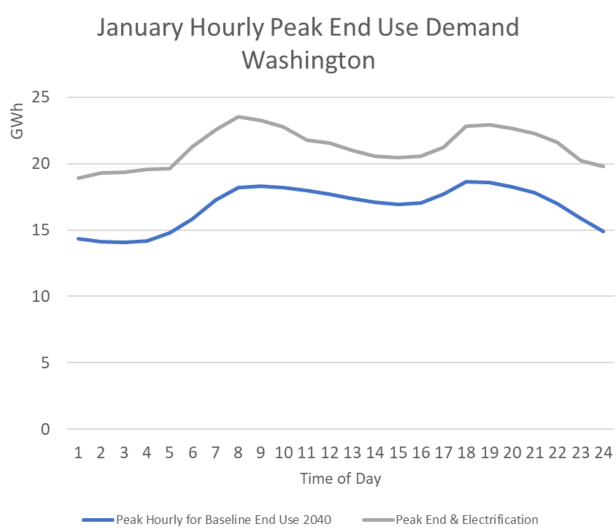
January Hourly Heat Pump Performance compared to Long Term Marginal Emissions Rate

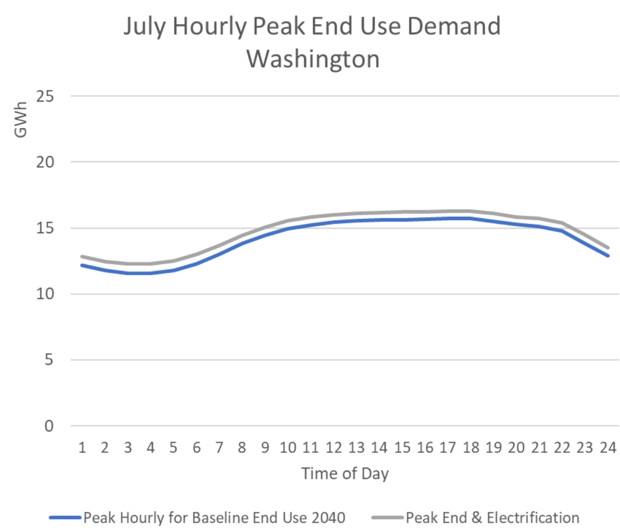


Daily Average Net Emissions for a Gas Furnace and a Cold Climate Heat Pump

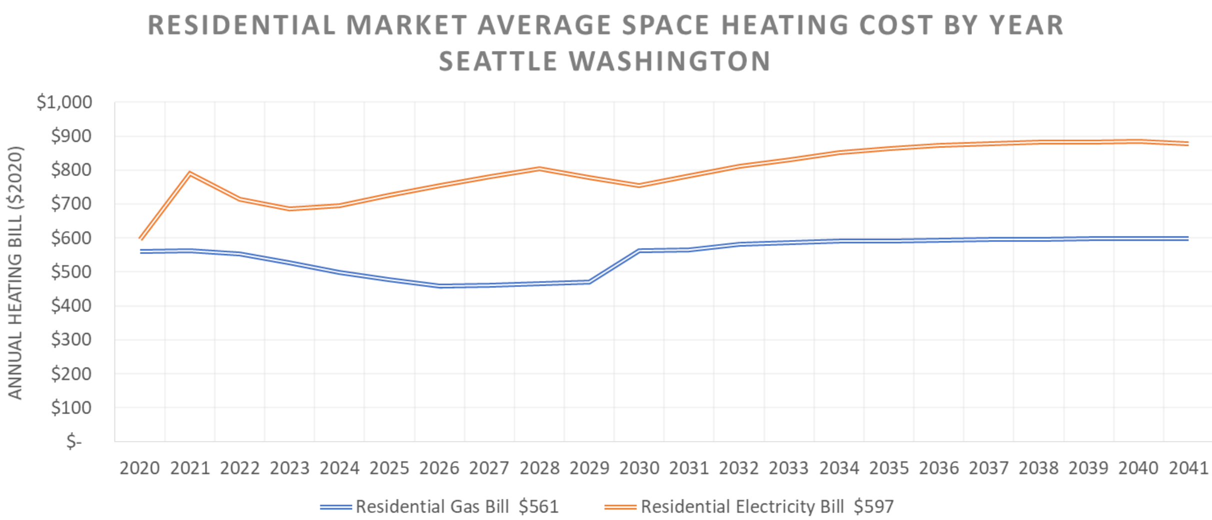


State Level Winter versus Summer Peak Electric Power End Use Demand





Annual Average Cost Difference for Gas Furnace and Cold Climate Heat Pump 2020 – 2041



Daily Average Net Cost for a Gas Furnace and a Cold Climate Heat Pump