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Seasonal Residential Space Heating Opportunities and Challenges

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Executive Summary

There are active policy discussions on future pathways for reducing greenhouse gas (GHG) emissions. To help inform those discussions, this report addresses opportunities and challenges with residential space heating energy use and GHG reductions. The main thrust is: (1) quantifying the magnitude of annual energy use and costs in residential space heating, (2) documenting issues with seasonal electricity generation for space conditioning loads, and (3) quantifying GHG comparisons between gas and electric space heating.

Energy Use

Information in this report covers forty-eight states, reflecting their current residential gas and electric energy use and estimated future peak monthly electricity use under an electrification scenario. For example, Figure 1 shows Illinois data with multi-year residential monthly gas and electricity use (left chart) plus current January and April residential energy use and projected future amounts under an electrification scenario (right chart). These energy use patterns vary by state depending on climate (e.g., heating and cooling degree days) and relative existing market shares for residential gas and electricity space heating.

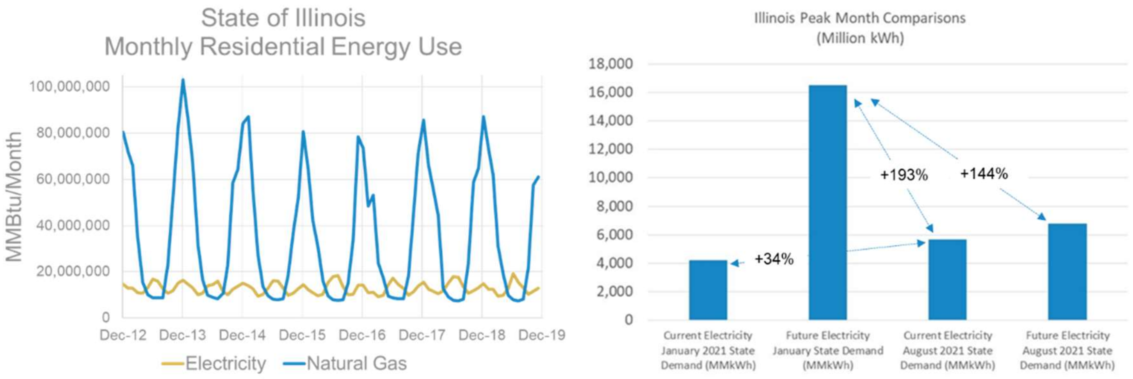


Figure 1: Illinois Residential Energy Use Comparison

A key consideration with electric space heating is the non-linear increase in electricity consumption as temperatures decrease. The issue becomes acute when extreme cold temperatures descend over a region for days or weeks; Figure 2 provides an illustration.

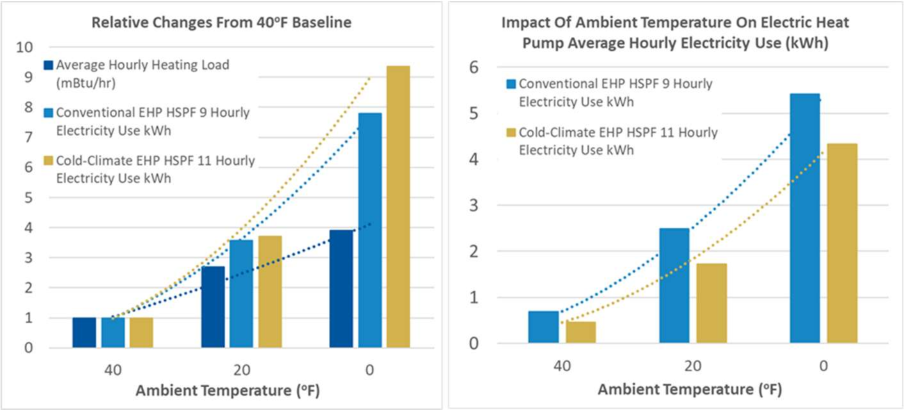


Figure 2: Impact of Ambient Temperature on Electric Heat Pump Electricity Use

Consumer Annual Space Heating Costs

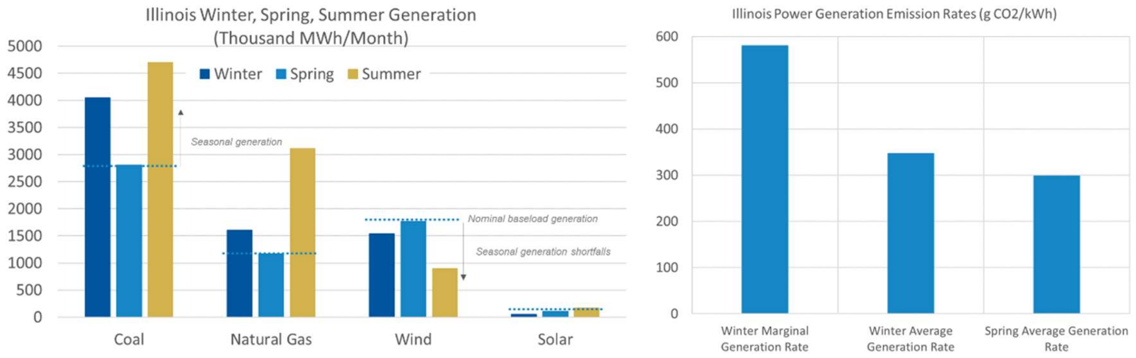
Electric space heating energy results in space heating cost increases of $411 per single-family home (66% average increase) when comparing a 94% efficient gas furnace and an HSPF 9.0 electric heat pump. Thirty-eight of forty-eight states showed an annual operating cost increase (79%). Costs are greatest in regions with considerable Heating Degree Days and/or high electric/natural gas price ratios. Across the US the average ratio of residential electricity to natural gas prices, based on 2021 DOE-EIA data, was 3.8:1.

Seasonal Electricity Generation

The report provides state-level data on three state-specific power generation market metrics:

- Spring Average Generation (e.g.., April, representing nominal Baseload Generation)
- Winter Average Generation (e.g., in January)
- Winter Marginal Generation (e.g., the specific GHG emission attributes of plants used to address January electricity demands from electric space heating)

Figure 3 is an example for Illinois; the report includes data for other states. This graph highlights a pattern seen in over 80% of states: (1) ramp up of dispatchable generation (e.g., gas and/or coal) to meet space conditioning loads in the summer or winter, (2) a decline in wind and solar generation in January, and (3) a higher Winter Marginal Generation Rate (gCO_2/kWh) used to meet electric space heating seasonal energy use.



Source: DOE-EIA 2021 data

Figure 3: Illinois Winter Marginal, Winter Average, and Spring Average Power Generation and CO_2 Generation Rates

Across the US, the median Winter Marginal Generation Rate results in a 53.5% increase in CO_2 emissions compared to the Spring Average Generation Rate; the amount varies depending on state-specific circumstances.

Greenhouse Emission Reduction Results

The following discussion on GHG emissions from gas and electric space heating options is based on using a 94% efficient gas furnace and an HSPF 9.0 electric heat pump. The report provides state-specific results using different electric generation scenarios (e.g., Winter Marginal versus Winter Average Generation Rates). Because of the unique seasonal nature of electric space heating, it is more appropriate to use the Winter Marginal Generation Rate for CO_2 emissions in a state for the coldest month (e.g., January) to get a real-world estimate of the GHG reduction potential of electric space heating.

Table 1 provides a summary of the GHG impact of switching from residential gas space heating to electric space heating under two different winter power generation emission rates: Winter Marginal and Winter Average. Using the Winter Marginal Emission Rate, the median change in emissions is an increase of 32.8% with higher emissions occurring in 29 states (60% of the 48 states). Using the Average Winter Emission Rate, the median change in emissions is -23.4% with an increase in 16 states (33% of the 48 states). A concerted focus on decarbonizing dispatchable generation such as natural gas combined-cycle plants would substantially alter these findings.

Table 1: Change in Emissions Switching from Gas to Electric Space Heating

CO_2 Emissions Impact of Changes from Gas to Electric Space Heating (48 States)	% Change in Space Heating CO_2 Emissions Using Winter Marginal Rate	% Change in Space Heating CO_2 Emissions Using Winter Average Rate
Median Change (%)	32.8%	-23.4%
Number of States with Emission Increases	29	16

Projected Seasonal Electricity Demand Changes with Statewide Electrification

Across these forty-eight states (Figure 4), the projected future winter peak for residential electricity would be 175% of the future summer peak. Winter peaks would occur in 45 of the 48 states (94%).

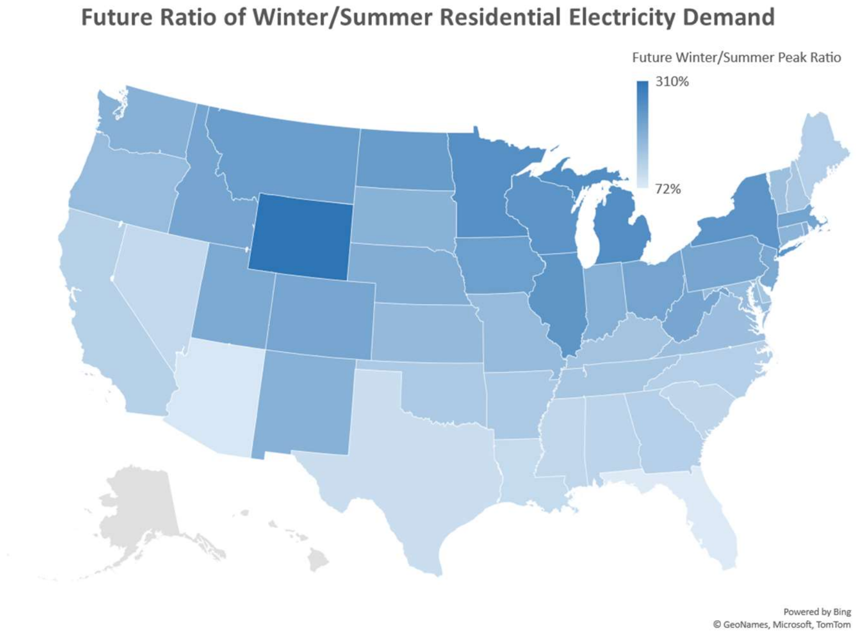


Figure 4: Impact of Electrification on Peak Winter Demand Compared to Summer Demand

Recommendations and Online Information Portal

Specific recommendations are contained at the end of this report. GTI developed an online portal providing state-level summary information for interested energy industry, policy, and regulatory stakeholders. Go to https://www.gti.energy/residential-space-heating for more information.

Introduction

There is active dialogue on policy considerations pertaining to future pathways for reducing greenhouse gas (GHG) emissions, including the GHG reduction scenario of replacing natural gas furnaces or boilers with electric space heating. This report addresses the opportunities and challenges with residential space heating and using electricity as an alternative approach.

The report is based on information from the United States (US) Department of Energy – Energy Information Administration (DOE-EIA) and modeling using a publicly available software developed by GTI called the Energy Planning Analysis Tool (EPAT) which captures full-fuel-cycle energy use and emissions. EPAT uses data from various entities, including the US Environmental Protection Agency (EPA) eGRID database, encompassing all state-level operating plants and their efficiency and environmental attributes. Efficiency and annual costs for gas and electric space heating equipment is based on independent information resources and represents real-world estimates of equipment performance in various climate regions across the country. Results are included on the forty-eight continental states.

The report provides objective information on the following topics:

- Expected changes in annual consumer energy costs between a baseline natural gas heating systems (94% furnace) and electric heat pump (HSPF 9.0)
- Variability in space heating energy demand as a function of region and outdoor ambient temperature and the implications for monthly (or shorter) electricity demand
- Electricity demand factors influencing variability in power generation supply attributes, with a particular emphasis on impacts during peak winter space heating seasons
- Coincidental and non-coincidental alignment of electricity demand and supply under an assumed large-scale adoption of residential electric space heating

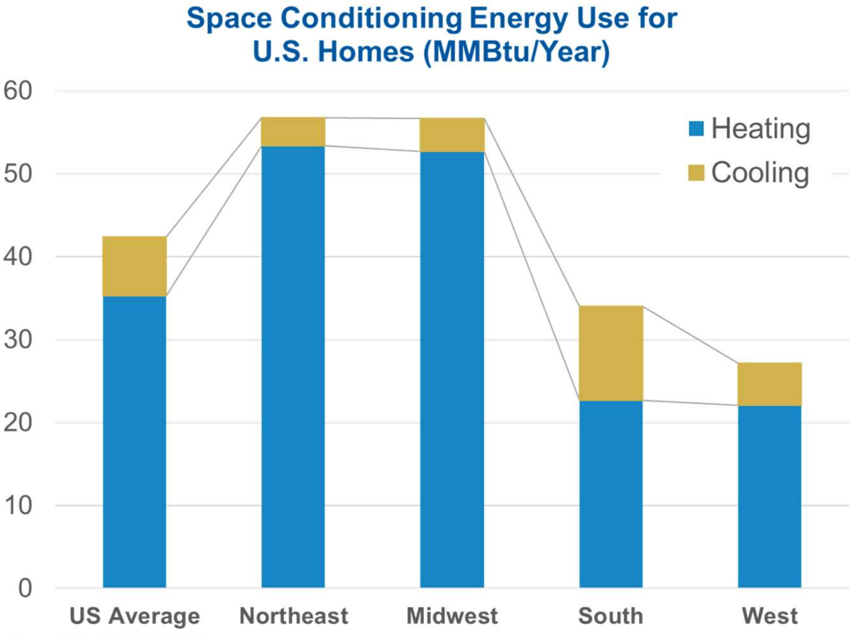
Reports by GTI and others discuss residential electrification in more detail, including the upfront capital and potential infrastructure costs associated with widespread residential electrification (e.g., see https://www.gti.energy/analyzing-residential-greenhouse-gas-ghg-emission-reductions/ for additional information) and importance of long-duration utility-scale energy storage (https://www.gti.energy/long-duration-utility-scale-energy-storage-white-paper/).

The report highlights key areas for further research and analysis:

- Addressing the impact of very cold ambient temperatures on electric heat pump performance, grid electricity demand, and consumer cold-weather operating costs
- Assessment of hybrid gas and electric space heating systems that simultaneously address consumer energy operating cost and grid sizing impacts
- Effect of seasonal electric space heating on the power generation plants used to meet multi-month peak energy demand requirements and their typically higher GHG emission rates compared to average or baseload power generation
- Focus on attention to pathways for decarbonizing dispatchable generation (e.g., natural gas combined-cycle plants) through renewable gas and/or CO_2 capture

Residential Space Heating Overview

Across the US residential sector, more energy is used for space heating than cooling – especially in colder-weather regions (Figure 5). As an approximation, the energy required for home space conditioning depends on temperature differences inside and outside the dwelling. For example, cooling a home from 90°F to 74°F is a temperature difference of 16°F, while heating a home from 20°F to 70°F is a temperature difference of 50°F (over three times greater). In addition, across much of the US, the duration of the heating season and runtime (hours) for space heating equipment is higher than the equipment runtime needed for cooling homes.



Source: DOE EIA (RECS, 2015)

Figure 5: Annual Average Space Conditioning Energy Use for US Homes

Heating and Cooling Degree Days (HDD and CDD, respectively) are metrics that account for: (1) space conditioning temperature differences (that is, between the outdoor and indoor temperatures) and (2) the number of days needed for heating and cooling. Figure 6 shows annual HDD and CDD values from 2000 to 2020 for the US and the East North Central region of the country (i.e., states of Ohio, Michigan, Indiana, Illinois, and Wisconsin). There are several key features of this graph: (1) the much higher number of HDD compared to CDD, (2) the large increase in HDDs that occurs in the northern regions of the country, and (3) the higher variability in HDD such as the spike in 2014 during an extremely cold winter. Space heating places extremely high demand on gas infrastructure today. Replicating that level of energy delivery capability with electricity – particularly during extreme cold weather events – is challenging.

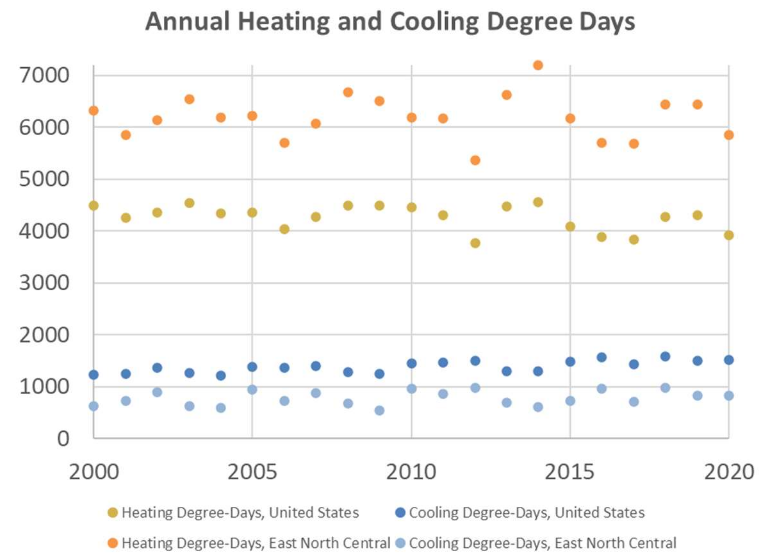


Figure 6: US and East North Central Region Annual Heating and Cooling Degree Days (DOE-EIA)

Figure 7 shows monthly electricity and natural gas energy use in Illinois homes over a seven-year period (2013 to 2019). Each sparkline graph is on the same monthly energy use scale, enabling direct comparisons. This highlights the larger seasonal gas energy required to heat Illinois homes compared to the peak electricity needed for cooling. A pattern of high natural gas winter peaks is seen across much of the US.

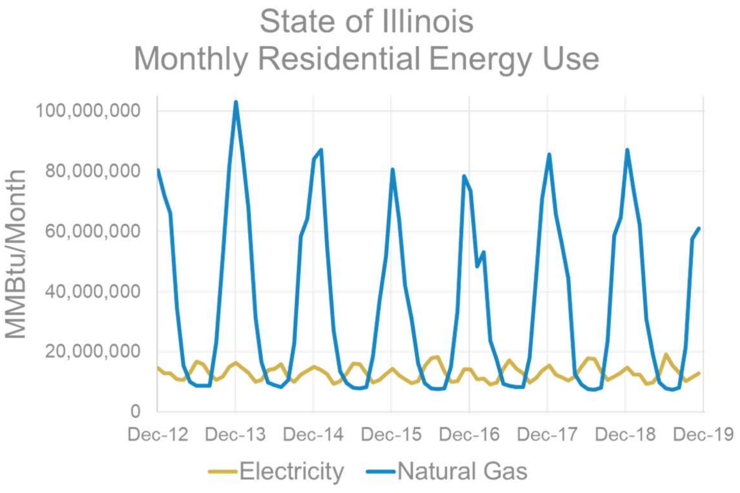


Figure 7: Monthly Residential Energy Use in Illinois Over Seven Years (DOE-EIA)

In many states, especially those with colder climates, natural gas is the preferred home heating energy choice. This is based on two favorable economic factors: (1) lower upfront capital costs (gas furnaces compared to electric heat pumps) and (2) lower annual energy costs. For homes that currently have electric space heating, the unfortunate reality is that over 60% use inexpensive and inefficient electric resistance heating; less than 40% of single-family homes with electric heating use heat pumps. Upgrading homes now saddled with electric resistance heating to an electric heat pump is a prime opportunity for cost-effectively improving consumer energy costs and reducing emissions.

Historically, electric heat pumps have experience challenges below about 40°F, including: (1) reduced heating capacity and lower supply air temperatures, (2) reduced system efficiency (or Coefficient of Performance, COP), (3) higher energy use for defrosting outside coils, and (4) increasing use of supplemental heating energy. At colder temperatures, electric heat pumps may require electric resistance heating for supplemental heat – which increases electricity consumption and peak power needs – and diminishes total electric heating efficiency. In other instances, homes may switch to supplemental heating from a gas furnace during cold periods to avoid using costly electric resistance heating (i.e., a hybrid gas/electric heating system).

Manufacturer ratings for electric heat pumps typically do not satisfactorily account for total, real-world energy use. Several factors can reduce electric heat pump efficiency, including: efficiency and capacity reduction from frost, snow, or dust accumulation on outdoor coils; electric energy used to defrost outdoor coils; standby parasitic power and cycling losses; efficiency and performance degradation from improper refrigerant charge; and energy required for supplemental heating at cold temperatures.

GTI has conducted extensive lab and field testing and computer modeling of electric heat pump performance and efficiency, including conventional and newer equipment characterized as cold climate (ccEHP) systems. Figure 8 shows representative performance data for electric heat pumps at colder temperatures (below 40°F). These data account for real-world conditions like defrosting outside air coils and standby power consumption. Conventional electric heat pumps with nominal HSPF values around 9 (over 90% of current sales) show decreasing COP values at colder temperatures and fall below 1.5 COP around 10°F. Higher-efficiency (HSPF 10 and above) cold-climate electric heat pumps have improved efficiency but show a decline in efficiency from 40°F down to 10°F and lower. Cold-climate heat pumps are a clear improvement but have higher first costs and are not yet representative of consumer choices.

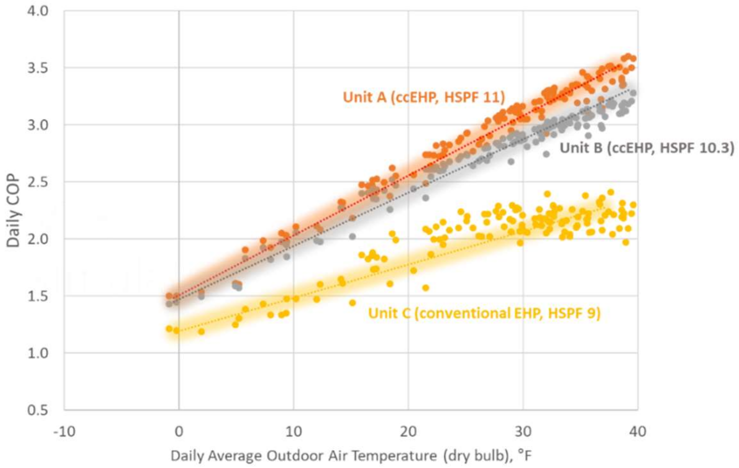


Figure 8: Electric Heat Pump Performance Below 40°F (Source: GTI)

Figure 9 provides further insights into the critical issue of non-linear increase in electricity use for space heating as outdoor temperatures drop. In this example, the building space heating load (shown in dark blue in left graph) increases by a factor of 2.7 at 20°F and by a factor of 3.9 at 0°F. Since electric heat pump efficiency (or COP) goes down with temperature, there is a compounded non-linear growth in average hourly electricity consumption at colder outdoor temperatures. For example, a conventional electric heat pump (HSPF 9, shown in light blue) will use 7.8 times more electricity at 0°F than at the baseline conditions of 40°F. The right figure shows an example of the absolute electricity consumed in an average hour as ambient temperatures change – with the more efficient heat pump using 9.3 times more electricity than at 40°F. Note that these data are based on a nominal, well-insulated 1,660 ft^2 home built to 2010 International Energy Conservation Code (IECC) building standards. Older homes and/or larger homes will have proportionately larger hourly electricity demands.

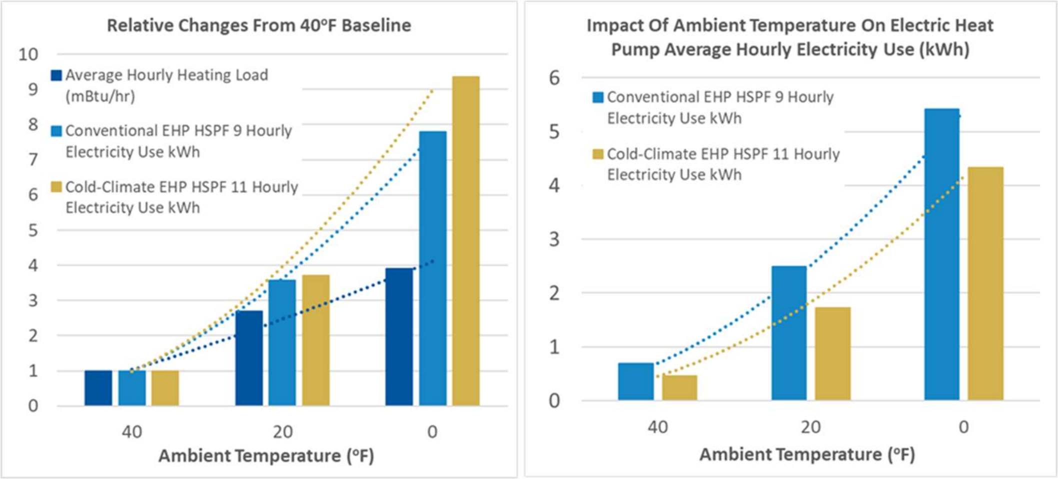


Figure 9: Impact of Ambient Temperature on Electric Heat Pump Electricity Use

In nearly all cases, operating electric heat pumps at very cold temperatures (e.g., below 10°F) leads to a notable drop-off in heating capacity and efficiency. This has serious implications for consumer energy costs and for power generation and infrastructure sizing. Some manufacturers indicate that electric heat pumps may need to shut off during extreme cold weather events (e.g., <-15°F) such as during a polar vortex event.

Electric heat pumps limitations at colder ambient temperatures raise several consumer and energy supplier concerns:

- Is a back-up home heating source available to ensure consumer comfort and safety?
- Will supplemental electric resistance heating substantially raise consumer heating bills?
- Will widespread simultaneous use of electric resistance heating at cold temperatures result in significantly higher peak-day electric power (generation, transmission, and distribution) asset requirements?

Recent events illustrate the impact cold temperatures have on electricity demand in regions where more than 50% of homes use electric space heating as their primary energy choice. Figure 10 shows DOE-EIA electricity usage in Texas in February 2021 as a function of outdoor temperature (based on the average daily temperature in Dallas, TX). During this period, a cold-weather front moved into Texas (and much of the US) over a multi-day period that led to a nearly 40% increase in total electricity demand; this increase is driven by electric space heating loads in the residential, commercial, and industrial sectors. This substantial increase in electricity demand due to cold temperatures could not be adequately met by all generation resources, leading to widespread outages over an extended period. While much discussion has centered on electricity supply, it is important to highlight this outage event was precipitated by electric space heating loads. Over 60% of Texas homes use electric space heating as their primary heating source.

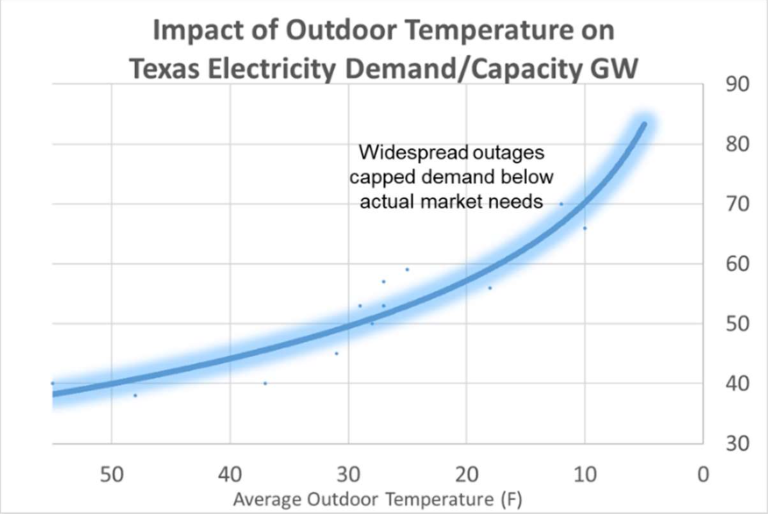


Figure 10: Impact of Cold Temperatures on February 2021 Electricity Demand

The February 2021 cold-weather event was an expensive incident that exposed consumers in multiple states to high personal safety risks and energy cost impacts. This empirical data reinforces the non-linear impact of cold temperatures on electricity demand (as shown in Figure 9). Adding more electric space heating loads places an enormous peak electricity burden on electric generation, transmission, and distribution systems – considerably more so than space cooling.

Figure 11 illustrates the full-cycle energy and CO_2 emissions rates of various natural gas and electric space heating pathways (e.g., gas furnace, gas heat pump, electric heat pump, and electric resistance heating). The gas and electric heat pumps show operation at at two ambient temperature conditions (10°F and 40°F). The electric scenarios tie back to being powered by natural gas combined-cycle power plants (typical power generation resources used for winter peak electricity loads). In this scenario, the electric heat pump can offer about 15% reductions in source energy and CO_2 emissions compared to a gas furnace but the same equipment – when operating at 10°F – increases total energy use and CO_2 emissions by nearly 37%. The electric heat pump will also be consuming over 60% more site electricity at 10°F than it does at 40°F – placing a high burden on the electric grid and energy costs to consumers. As illustrated, electric resistance space heating is the most inefficient and highest CO_2 emissions pathway for heating a home under this scenario.

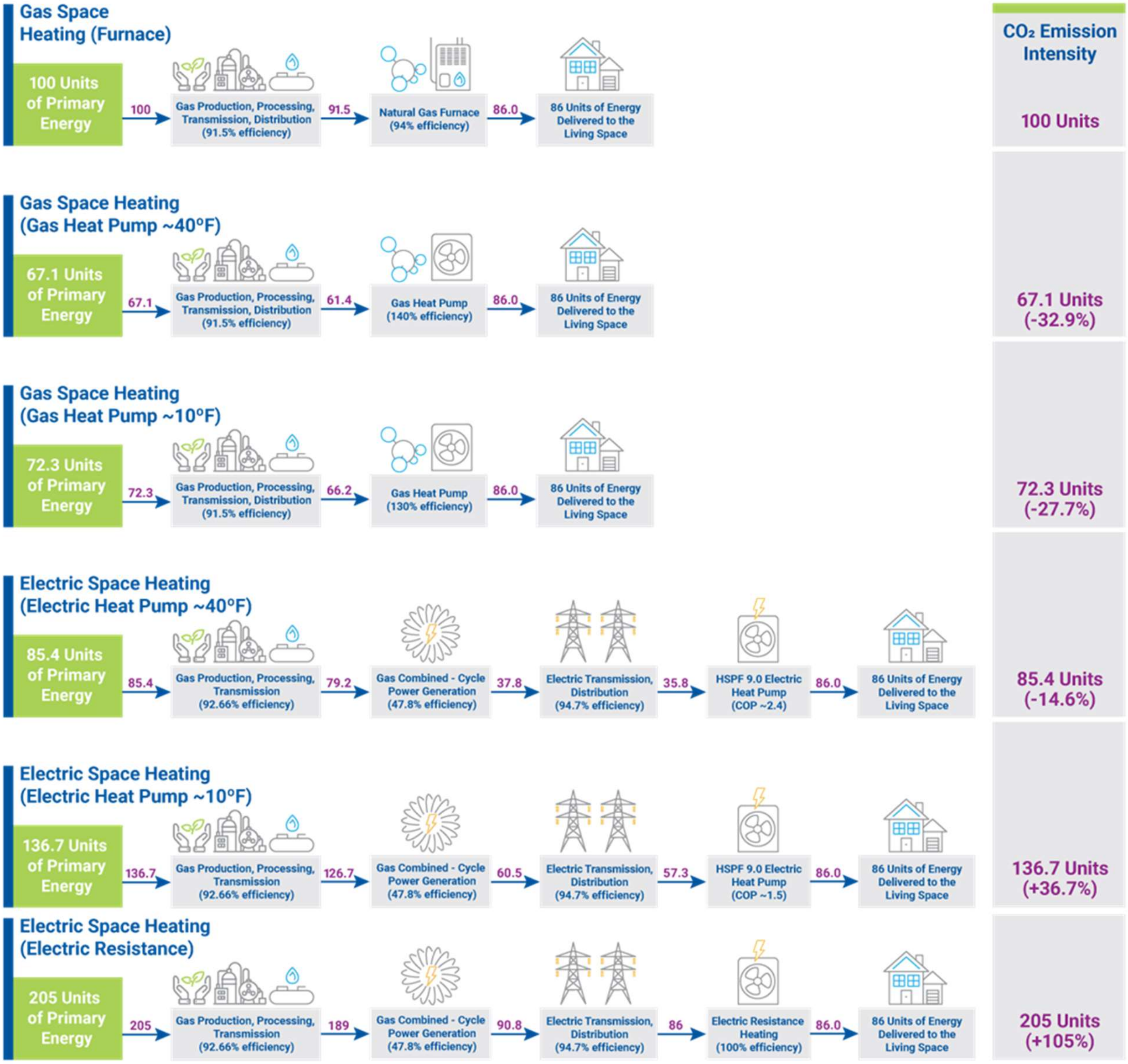
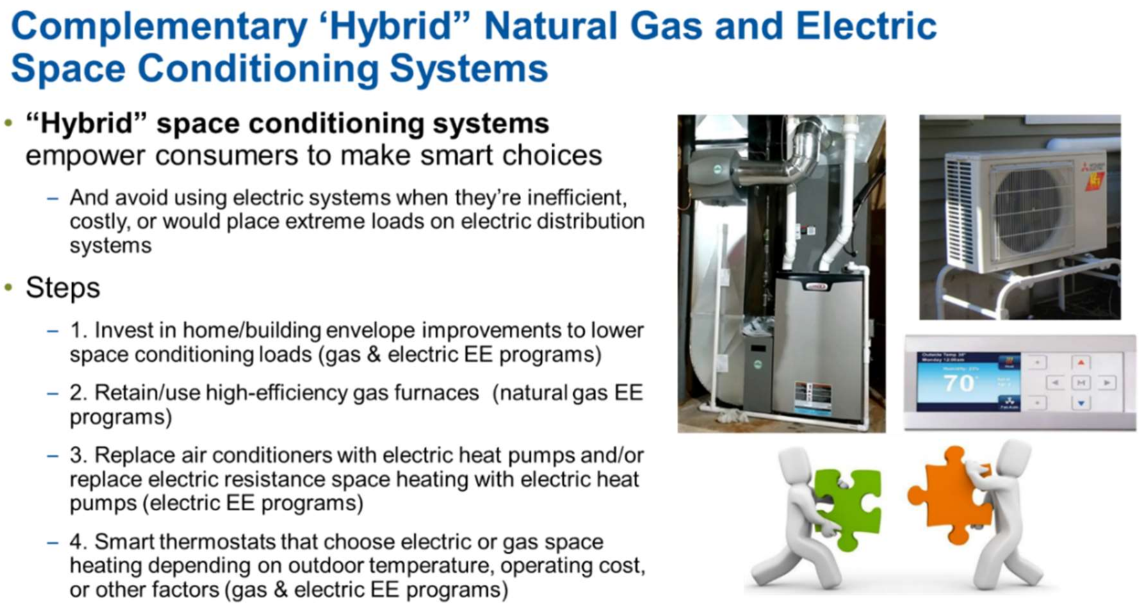


Figure 11: Full-Fuel-Cycle Comparisons of Gas and Electric Heating Pathways

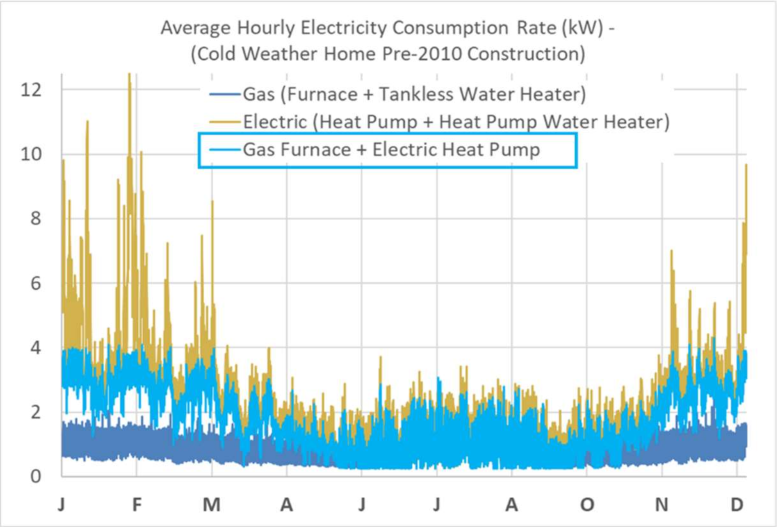
Complementing electric heat pumps with natural gas heating equipment (i.e., hybrid gas/electric systems) and using natural gas to satisfy heating loads at colder temperatures helps ameliorate consumer and societal cost impacts (Figure 12 and Figure 13). It also empowers consumers and utilities with choices. Supplemental gas heating is a cost-effective peakshaving approach to avoid significant spikes in electric demand during cold periods when electric heat pump efficiency declines and electricity use goes up. Supplemental gas heating also reduces an electric heat pump's annual runtime which may extend equipment years of service. A hybrid heating strategy also avoids running electric heating equipment mainly on dispatchable power generating systems (e.g., natural gas combined-cycle plants) that are likely to have higher GHG emission rates.



Complementary 'Hybrid" Natural Gas and Electric Space Conditioning Systems

- **"Hybrid" space conditioning systems** empower consumers to make smart choices
  - And avoid using electric systems when they're inefficient, costly, or would place extreme loads on electric distribution systems
- Steps
  - 1. Invest in home/building envelope improvements to lower space conditioning loads (gas & electric EE programs)
  - 2. Retain/use high-efficiency gas furnaces (natural gas EE programs)
  - 3. Replace air conditioners with electric heat pumps and/or replace electric resistance space heating with electric heat pumps (electric EE programs)
  - 4. Smart thermostats that choose electric or gas space heating depending on outdoor temperature, operating cost, or other factors (gas & electric EE programs)

Figure 12: Natural Gas and Electric Hybrid Heating Systems



Detailed 8,760 hour residential home energy model.

All-electric home space heating results in massive increases in peak winter demand.

Hybrid heating approach with natural gas furnace and electric heat pump (run on mild winter days) dramatically lowers peak electric demand impacts and related negative issues.

Figure 13: Hybrid Natural Gas and Electric Space Heating System Modeling (GTI; New York State home)

Seasonal Electric Generation for Space Conditioning

Within the forty-eight continental US states, there are differences in: (1) the mix of power generation plants and (2) within a state, variation in the types of plants used during the year (e.g., month-to-month changes in output from different types of generation resources).

This section discusses variability in the mix of state-level power generation such as changes in output due to weather or seasonal factors (e.g., variation in wind intensity for wind generation or length of daylight hours for solar generation) as well as a review of the types of power generation facilities used to address demand-driven, non-baseload, seasonal electricity loads for space conditioning (i.e., heating or cooling). Month-to-month and seasonal variability in the types of generation have important implications for using electricity as a GHG reduction strategy for winter space heating loads.

The following information is based on DOE-EIA 2021 data for these states and uses EPA eGRID statewide plant information to quantify the varying attributes of state-level GHG emissions as a function of winter electricity demand. Specifically, three state-specific power generation market segments are analyzed:

- Spring Average Generation (nominal Baseload Generation)
- Winter Average Generation
- Winter Marginal Generation (e.g., the specific GHG emission attributes of plants used to address seasonal multi-month winter electricity demands from electric space heating)

Overview of the US Power Generation Sector

The US electric power generation sector (Figure 14) has undergone significant change since 2005, driven by the growth of natural gas, wind, and solar power generation sources along with a precipitous decline in coal generation (made possible by the retirement of a large fleet of aging coal power plants).

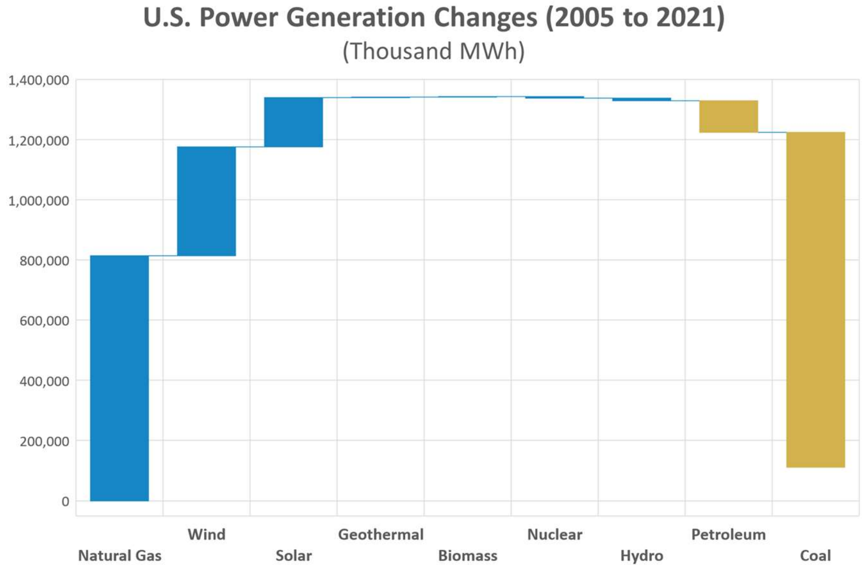


Figure 14: Changes in US Power Generation Output (2005–2021, DOE-EIA)

Figure 15 shows trends in the US power generation average CO_2 emission rate since 2005. There has been remarkable progress across the country, with a nearly 37% reduction in CO_2 intensity per unit of electricity delivered and an average of about 375 g CO_2/kWh in 2021. This trend is likely to continue in the 2020s as more coal power generation plants are retired or have reduced annual capacity factors. At some future point, there is an inevitable shift as coal constitutes a smaller fraction of the overall US generation mix. For example, coal's share of the power generation market was 50% in 2005 and now is below 22% in 2021. The California experience over the past 15 years may be an indicator of next-phase challenges in achieving power sector GHG emission reductions (i.e., the need to decarbonize firm dispatchable gas generation).

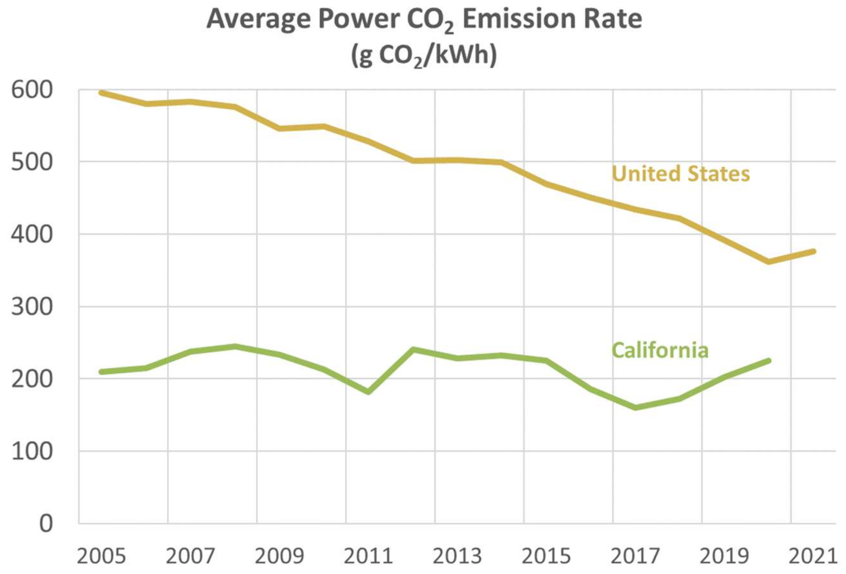


Figure 15: US and California Power Generation CO_2 Emission Rate (DOE-EIA)

Seasonal and Non-Baseload Power Generation

The prior section lays out macro-level, multi-year annual trends in the US power generation market. There are key intra-annual considerations associated with generating power for building space conditioning: seasonality. The implications of seasonality are often not sufficiently highlighted in building electrification policy discussions yet is a significant factor and potentially problematic in terms of grid sizing and capturing real-world GHG benefits.

As shown in Figure 7, seasonal gas space heating loads are vastly larger than seasonal electricity cooling loads in many regions. As states contemplate expanded building electrification, there could be a significant increase in winter electricity demand if electric space heating achieves high levels of market penetration. There are two important components of greater reliance on electric space heating: (1) the expanded level of demand impacting sizing of generation, transmission, and distribution assets and (2) the nature of the GHG emissions from generation resources normally deployed to address higher electricity demand on a seasonal basis.

High penetration of electric space heating would shift electric demand peaks to the winter (e.g., peak month in January) and in colder regions this peak month would substantially exceed peak summer demand.

Figure 16 illustrates this situation across the US. This shows generation levels for dispatchable generation (i.e., coal and natural gas) and less-firm sources (i.e., wind and solar) which exhibit seasonal changes in generation level; this figure is based on DOE-EIA 2021 data for the months of January, April, and August. Salient features include the distinct increase in coal and natural gas generation during the winter and summer seasons to address incremental electricity use for space conditioning. That is, the mix of plants used to meet these space conditioning loads are notably different than baseload generation (the month of April serves as a proxy for baseload generation in this and subsequent state-level graphs). Notably, the net increase in gas or coal generation is often accompanied by a seasonal decrease in winter and/or summer generation from wind and solar. There is a large drop in winter solar output but a favorably coincident increase with summer electricity demand increases for cooling.

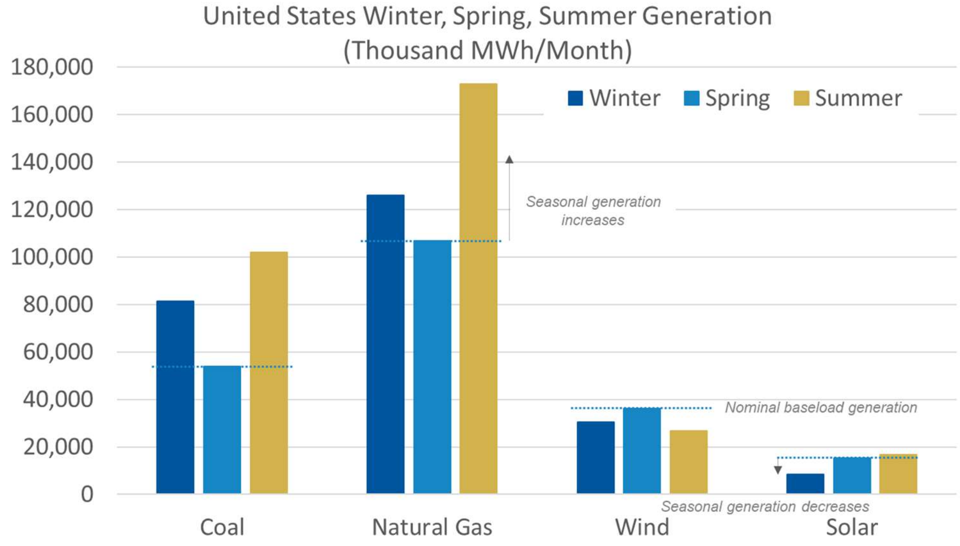


Figure 16: US Seasonal Generation Comparison in Four Supply Segments (DOE-EIA)

As shown in Figure 17, while spring average emission levels have decreased over 30% since 2013 there has been very little change in the winter and summer marginal generation rates. This highlights the importance of decarbonizing dispatchable generation resources.

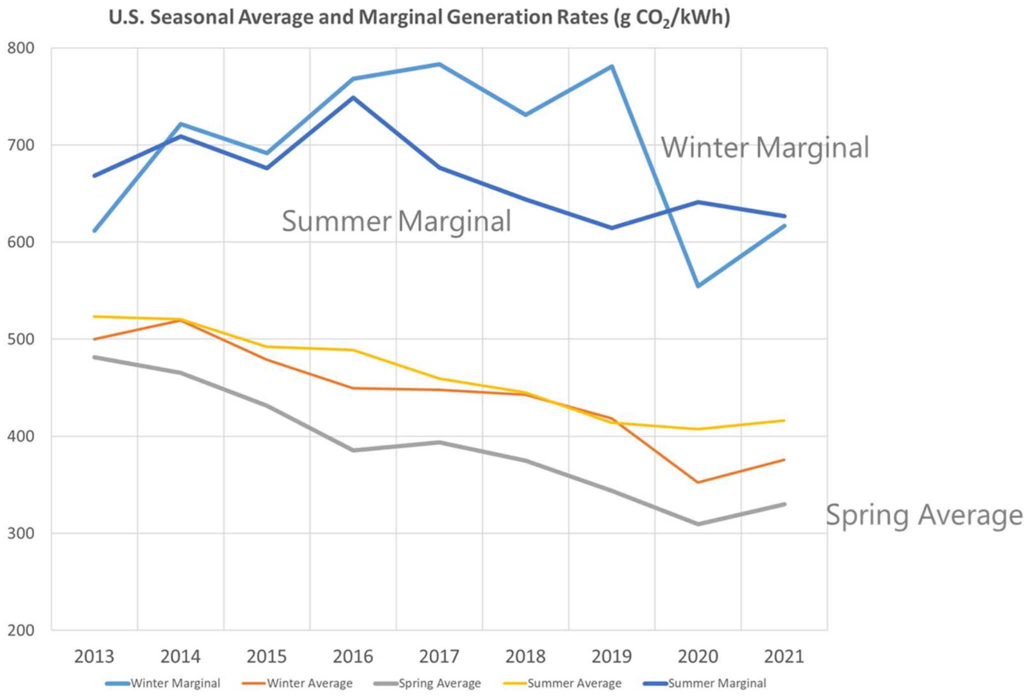
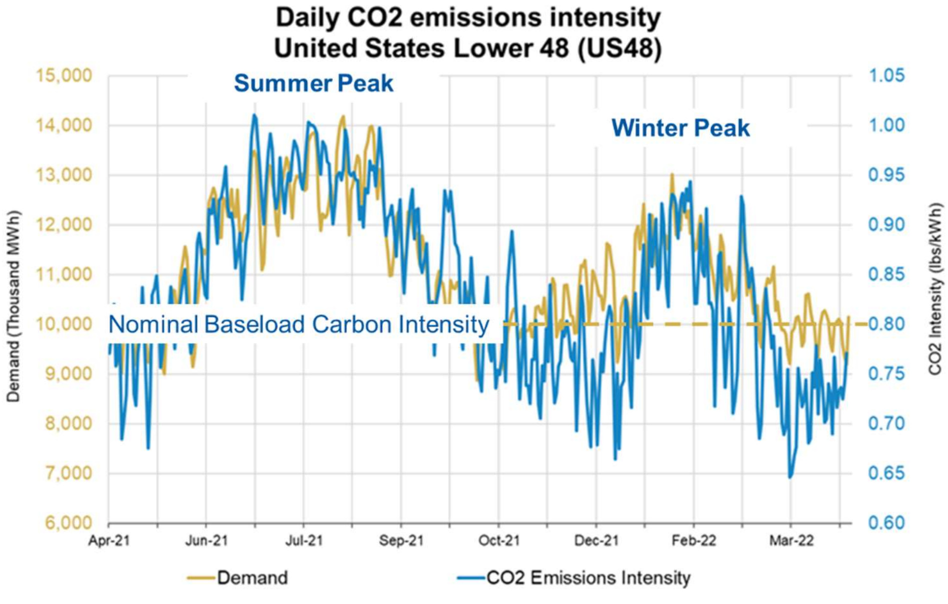


Figure 17: U.S. Average and Marginal Power Generation CO_2 Emission Trends

When looking at electric space heating as a GHG reduction strategy, there are critical issues arising from these figures. Currently in the US (and in most states), increases in electricity demand during January are met by increasing coal and/or natural gas generation output. As firm and dispatchable plants, these generation resources are capable of “flexing up” output for several months during winter and summer to address space conditioning loads. In nearly all states, however, wind and solar generation declines during the winter; this is particularly significant with solar PV generation which can decline by 50% or more during winter periods. In addition to gas or coal resources being called upon to address higher winter electricity loads, in most states gas or coal generation resources also need to ramp up production to compensate for wind and solar generation reductions in January. These operating practices have important real-world implications when contemplating the broader use of electric space heating as a GHG reduction strategy.

Figure 18 provides an illustration based on one-year DOE-EIA national data covering daily US electricity demand and power generation CO_2 emissions intensity. While baseload electricity demand is met with a power generation mix having a nominal 0.8 lb CO_2/kWh CO_2 (363 g CO_2/kWh) carbon intensity, seasonal electricity peaks in the summer and winter increase CO_2 emission rates by about 10-25%.



Source: U.S. Energy Information Administration, Form EIA-930, 'Hourly and Daily Balancing Authority Operations Report'

Figure 18: One-Year of US Electricity Demand and Generation CO_2 Intensity (DOE-EIA)

It is possible to estimate the winter seasonal (or summer seasonal) marginal CO_2 generation rates. That is, the specific CO_2 generation intensity for the power generation plants (e.g., operated over an entire month) brought online to address the marginal or incremental demand for electricity in the winter (or summer) months from space conditioning demand increases. This report calculates and uses the Winter Marginal Generation Rate CO_2 intensity in individual 48-continental states. Appendix B shows an example calculation.

The Winter Marginal Generation Rate is calculated for each state that currently experiences a winter peak in electricity demand (i.e., in January) in comparison to an off-peak month (i.e., April). State-level data is used from DOE-EIA on monthly electricity generation in each state and along with EPA eGRID statewide power plant data to determine the average CO_2 emission rates in January and April in each individual state. The Winter Marginal Generation Rate is calculated based on empirical data in each state using actual operating plants and electricity generation.

The Winter Marginal Generation Rate (or CO_2 Intensity) is an appropriate measure for quantifying the current state of adding new electric space heating demand in those states. As noted previously, while new wind and solar generation support baseload generation, these resources in nearly all cases experience a decline in output during the winter period and are not capable of “flexing up” output to meet seasonal electric space heating loads. The lack of electric utility long-duration energy storage (e.g., multi-week or multi-month) makes it unlikely that wind and solar can meaningfully address peak winter month demand for electric space heating.

In today’s market, the effect of adding electric space heating results in consuming electricity at the Winter Marginal Generation Rate. More winter electricity loads such as electric space heating in January have the effect of increasing use of natural gas or coal generation and raising the Average Winter Generation Rate. This has important implications in terms of using electric space heating as a GHG reduction strategy. As will be discussed, this impact could be mitigated through implementation of GHG reduction strategies such as using renewable gas and/or the use of CO_2 capture in natural gas power plants.

For this reason, we present results that include the impact of the Winter Marginal Generation Rate to reflect the ability to capture real-world GHG emission reductions during the cold winter months such as January in individual states. It is noteworthy that this aspect of the power generation is substantially lessened at milder temperatures during the months before or after the more intense winter periods.

The following examples show the Winter Marginal Generation Rate for Texas (Figure 19), Colorado (Figure 20), Illinois (Figure 21), and New York (Figure 22). While the absolute values of the power generation emission rates in these states vary based on their power generation mix, there are consistent patterns: (1) an increase in natural gas and/or coal generation in the winter, (2) decline in January wind and solar generation, and (3) increases in the Winter Average and Winter Marginal emission rates (compared to Spring Average emission rates).

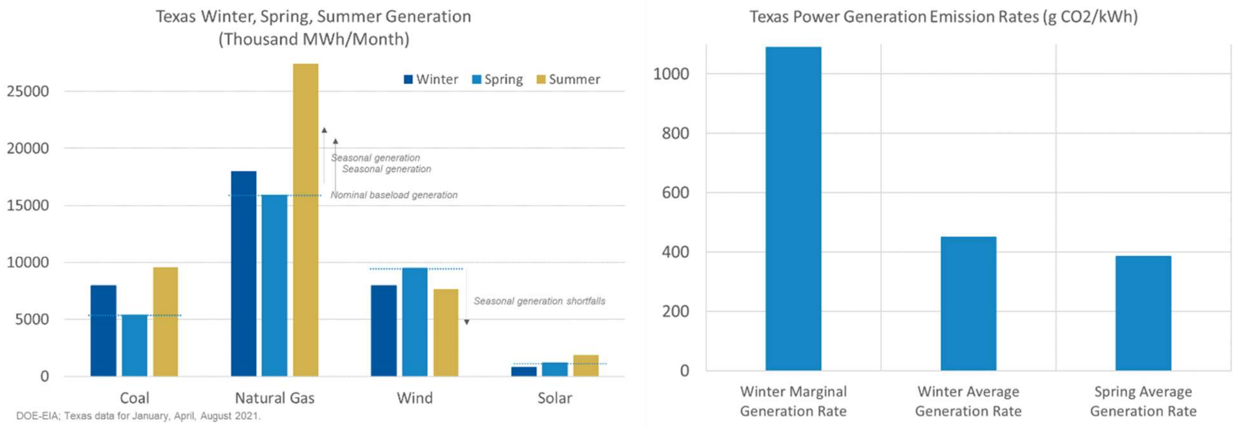


Figure 19: Texas Winter Marginal, Winter and Spring Average CO_2 Generation Rates

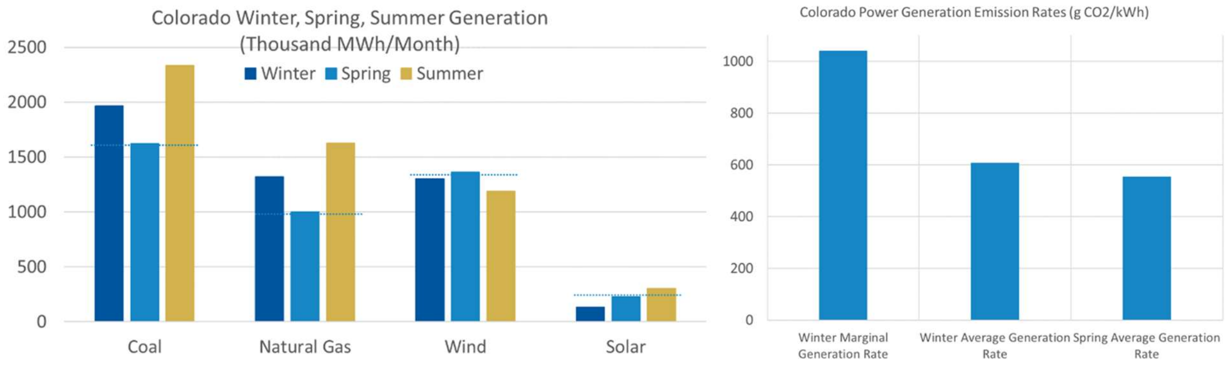
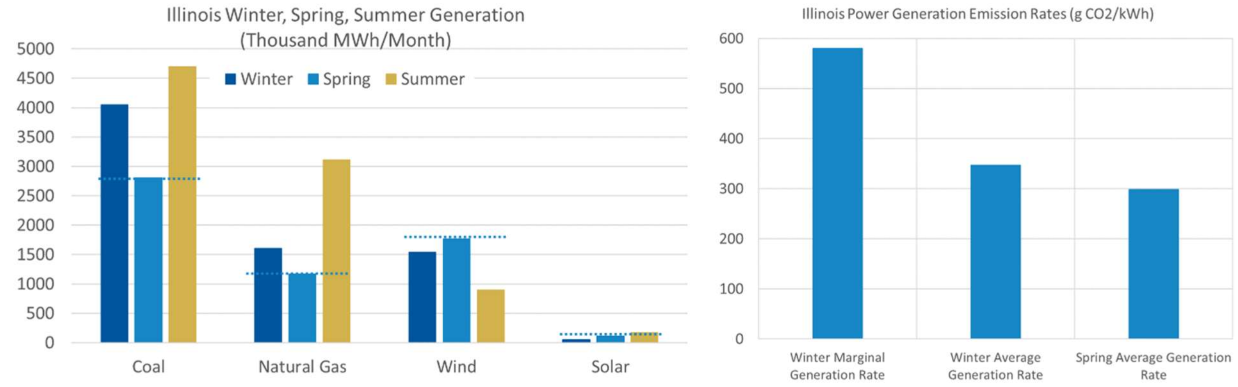
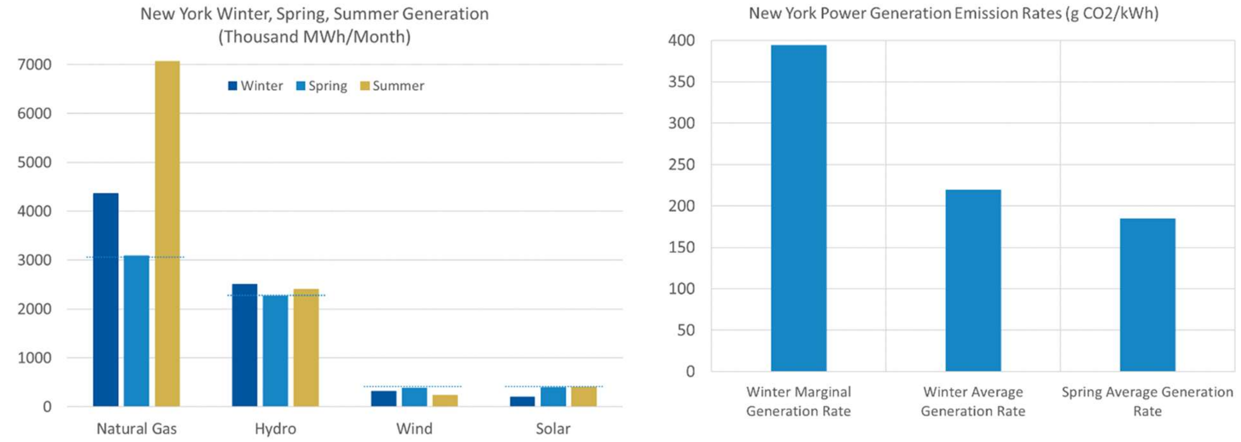


Figure 20: Colorado Winter Marginal, Winter and Spring Average CO_2 Generation Rates



Source: DOE-EIA 2021 data

Figure 21: Illinois Winter Marginal, Winter and Spring Average CO_2 Generation Rates



DOE-EIA 2021 data.

Figure 22: New York Winter Marginal, Winter and Spring Average CO_2 Generation Rates

Figure 23 and Table 2 provide a summary of the US median and 48 state-specific analysis for the Seasonal Average and Winter Marginal Generation Rates. Analysis of these data indicate overall trends where Winter Marginal Generation Rates for CO_2 emissions are 47% higher than the Winter Average rate and 53.5% greater than the Spring Average. The Winter Marginal rates exceed the winter and spring averages in nearly all cases (83% of the states). These results are used to analyze the impact of state-specific peak winter electric space heating demand on full-cycle CO_2 emission rates for a typical single-family home.

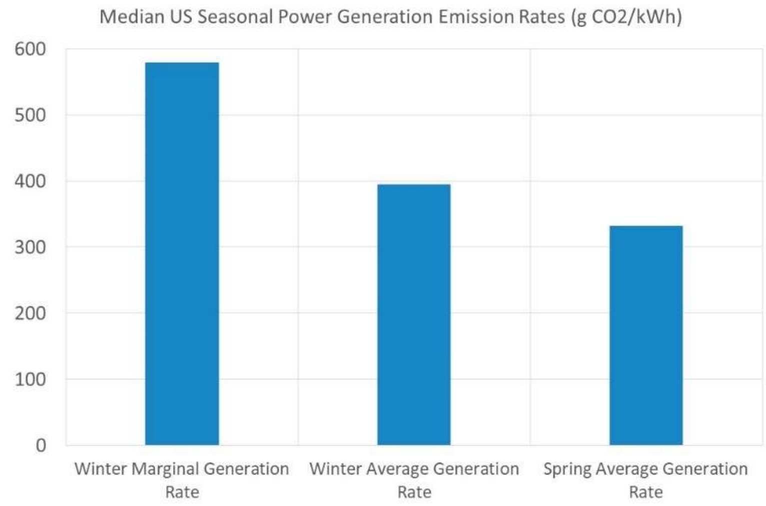


Figure 23: US Median Seasonal CO_2 Emission Rates

Table 2: Seasonal Average and Marginal CO_2 Generation Rates

	eGRID Electric Winter Average CO_2 Emissions Rate (g/kWh)	Electric Spring 2021 Average CO_2 Emissions (g/kWh)	Electric Winter Marginal Case CO_2 Emissions (g/kWh)	Percent Change Spring to Winter Marginal Emission Rate
Median US Case	394	331	579	53.5%
Alabama	339.1	341.2	333.5	-2.2%
Arizona	341.0	337.0	402.7	19.5%
Arkansas	594.4	433.8	1024.8	136.2%
California	236.2	175.5	236.2	34.5%
Colorado	606.7	552.8	1039.3	88.0%
Connecticut	253.1	231.9	431.8	86.2%
Delaware	336.1	394.0	476.1	20.8%
Florida	408.6	411.5	516.5	25.5%
Georgia	376.3	334.1	811.0	142.7%
Idaho	101.2	87.6	135.8	55.0%
Illinois	347.4	298.1	580.1	94.6%
Indiana	798.1	737.5	938.7	27.3%
Iowa	387.7	241.2	2808.8	1064.4%
Kansas	388.7	333.2	989.0	196.8%
Kentucky	831.4	845.3	780.2	-7.7%
Louisiana	414.9	427.0	319.7	-25.1%
Maine	119.9	90.0	273.7	204.0%
Maryland	405.0	255.1	3109.5	1118.7%
Massachusetts	399.8	288.2	577.8	100.5%
Michigan	509.2	412.2	819.5	98.8%

Minnesota	410.6	267.2	1076.1	302.8%
Mississippi	413.7	385.1	495.5	28.7%
Missouri	695.0	758.0	493.1	-34.9%
Montana	505.9	420.0	614.8	46.4%
Nebraska	564.9	400.1	1447.5	261.8%
Nevada	351.5	303.9	351.5	15.7%
New Hampshire	145.2	102.5	507.2	395.0%
New Jersey	201.7	222.9	201.7	-9.5%
New Mexico	633.9	420.6	1294.2	207.7%
New York	219.4	184.6	393.8	113.4%
North Carolina	400.7	308.9	710.5	130.0%
North Dakota	166.0	94.5	2910.8	2979.3%
Ohio	612.6	580.1	707.4	21.9%
Oklahoma	343.1	242.7	899.3	270.6%
Oregon	139.8	175.7	139.8	-20.5%
Pennsylvania	403.7	367.3	502.0	36.7%
Rhode Island	406.2	328.2	525.9	60.3%
South Carolina	292.6	255.2	459.7	80.1%
South Dakota	158.1	100.2	2380.1	2274.3%
Tennessee	270.5	326.4	270.5	-17.1%
Texas	450.2	385.0	1089.2	182.9%
Utah	764.7	668.7	764.7	14.4%
Vermont	5.8	4.2	5.8	38.0%
Virginia	295.2	310.3	295.2	-4.9%
Washington	89.0	78.6	89.0	13.3%
West Virginia	944.3	909.1	944.3	3.9%
Wisconsin	621.1	571.4	868.2	52.0%
Wyoming	866.1	847.8	866.1	2.2%

Decarbonization of Dispatchable Generation

This section contains a brief review of options for decarbonizing dispatchable natural gas generation (e.g., natural gas combined-cycle power plants). This includes: (1) renewable gas such as renewable methane (CH_4) and other hydrogen (H_2) and (2) carbon capture and storage.

Renewable gas can be produced from various renewable resources, including:

- Conventional anaerobic digestion pathways produce bio-methane from landfills, wastewater treatment plants, farm digesters, and other sources; these are mature pathways
- Thermochemical conversion (e.g., gasification) pathways that produce renewable methane or hydrogen from biomass materials (e.g., wood waste and agricultural waste)
- Power-to-gas concepts using renewable or zero-carbon power generation sources (e.g., wind, solar, nuclear) to produce hydrogen via water electrolysis

Figure 24, from the American Gas Foundation (AGF), provides a visual description of these renewable gas pathways and the energy sources that can be used to produce renewable gases.

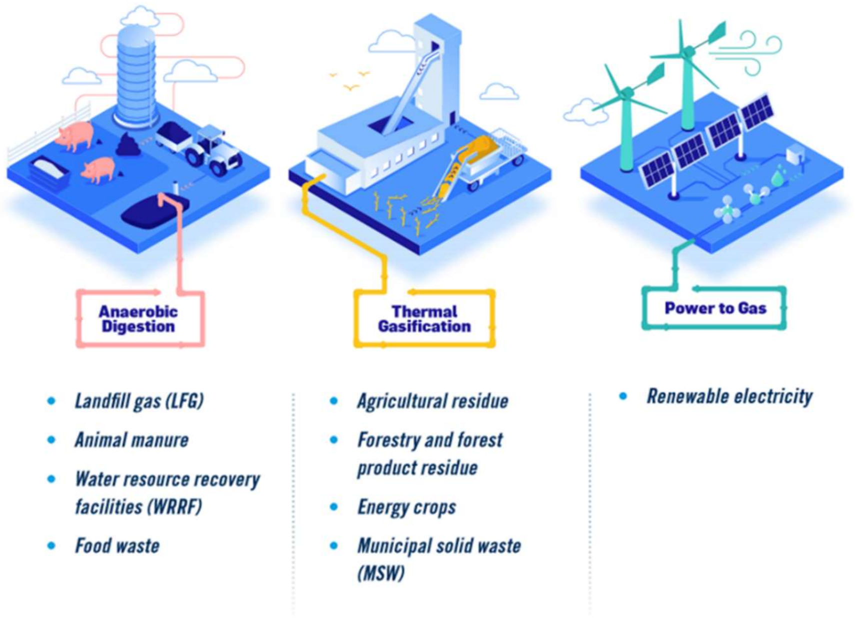


Figure 24: Renewable Gas Generation Pathways (Source: American Gas Foundation)

Renewable gas is an energy form – that is, chemical energy – is important for several reasons:

- Intrinsically high energy density
- Readily and efficiently stored as a compressed gas and compatible with existing gas storage assets
- Potentially compatible with existing gas pipeline infrastructure and end-use equipment
- Efficiently delivered to customers with minimal energy losses

The AGF report, produced by ICF, indicates substantial US potential for three renewable gas pathways (Figure 25). The 2040 potential for renewable gas is equivalent to about 4,512 Trillion Btu/year. This is comparable to the total amount of natural gas consumed in the US residential sector or to about 40% of the current amount of gas used for power generation.

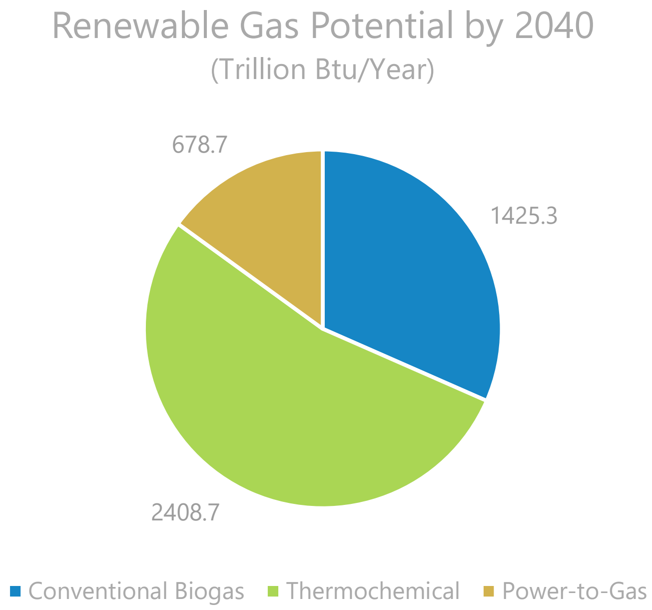


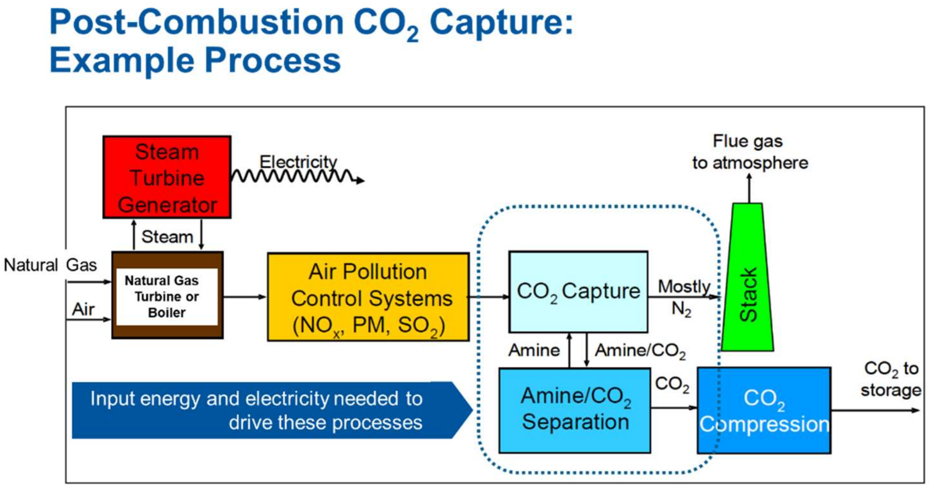
Figure 25: American Gas Foundation/ICF Renewable Gas Potential

Next-generation renewable gas options are possible through (1) thermochemical conversion of biomass and (2) power-to-gas systems. These are not yet widely reduced to commercial practice but have long-term potential to expand the portfolio of renewable and sustainable forms of methane or hydrogen.

Thermochemical conversion of biomass to methane or hydrogen has several favorable attributes, including feedstock flexibility and greater capability to produce large volumes of renewable gas. These processes can convert agricultural wastes, forestry wastes, organic municipal wastes, and byproducts from a variety of industries. These facilities are typically 2-10 times larger than conventional biogas facilities.

Power-to-gas is a pathway that produces hydrogen through the electrolysis of water. The power can come from any electrical source but is often viewed in the context of wind and solar power (as a means of storing excess power generation) or from nuclear power plants. This hydrogen can be used directly, stored as a compressed gas, or injected into a pipeline. Through a process called methanation, it can also be combined with captured and recycled CO_2 to produce methane, which can be used directly with existing natural gas infrastructure.

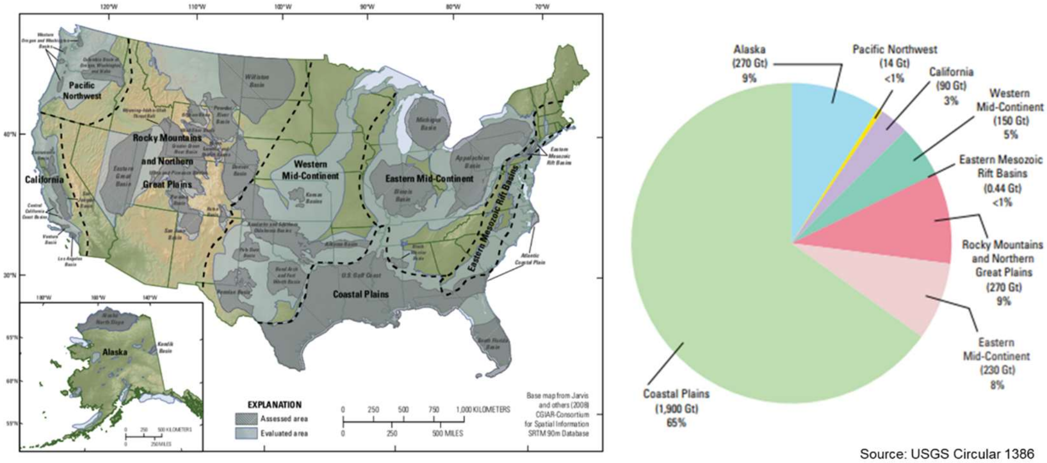
Carbon Capture and Storage is a secondary pathway for decarbonizing natural gas combined-cycle power plants. Figure 26 shows an example CO_2 exhaust capture process. The CO_2 produced from this process can be sent to a pipeline for shipment to an underground storage facility or employed in a CO_2-reuse approach.



Adapted from: **Source:** E. S. Rubin, "CO_2 Capture and Transport," *Elements*, vol. 4 (2008), pp. 311-317.

Figure 26: Example CO_2 Capture Process

There is a growing attention to CO_2 pipeline and storage systems, driven in part by Federal 45Q tax credits and market efforts to reduce the carbon intensity of various segments (e.g., major industrial and power generation facilities). There are potential subsurface CO_2 storage locations throughout the US (Figure 27).



Source: USGS Circular 1386

Figure 27: US CO_2 Storage Potential

State Analysis: Residential Space Heating Consumer Energy Costs, GHG Emission Rates, and Residential Electricity Demand

This section highlights information on gas and electric energy costs, energy demand, and GHG reduction potential in 48 states. This analysis is based on a free, publicly accessible online tool developed by GTI: Energy Planning Analysis Tool (EPAT; http://epat.gastechnology.org/).

Energy Planning Analysis Tool (EPAT) Analysis

EPAT is a no-cost publicly accessible analytical tool for conducting a state or local energy and environmental analysis of various home energy uses. EPAT relies on government published and publicly available data sources to estimate source energy (i.e., full-fuel-cycle) and emissions for energy sources like natural gas and electricity consumed at a site. EPAT accounts for upstream energy use and emissions in the production and delivery of energy, including features such as methane emissions from the full natural gas production and delivery chain as well as full-fuel-cycle energy losses and emissions from electric power generation, transmission, and distribution. The EPAT electric generation component relies on EPA eGRID data, with granular information on power generation plant efficiency and emissions on a city, state, or regional level. In this analysis, we focus on a comparison of natural gas and electric space heating in various states. An example state-level EPAT report with full-cycle energy and environmental data is available in Appendix A. The data in this report was generated using the version of EPAT available in March, 2022 using EPA eGRID2020 (released January 27, 2022) data and EPA GHGI 2019 data.

Natural Gas and Electric Space Heating Cost Comparisons

Table 3 provides a summary of the state-level residential gas and electric annual space heating energy cost comparison. On average, a shift from natural gas to electric space heating for a typical single-family home (1600-2000 ft^2) resulted in an average annual increase of $411 across all states (66% increase) based on 2021 state average electric and gas costs from DOE-EIA. Space heating costs would increase in 38 of the 48 states (79%).

Table 3: State-Level Gas and Electric Space Heating Energy Cost Comparison

	Gas Cost ($/year)	Electric Cost ($/year)	Change in Space Heating Annual Energy Costs ($)	% Change in Space Heating Annual Energy Costs	Electric/ Gas Price Ratio
Alabama	$392	$332	-$60	-15%	2.4
Arizona	$234	$225	-$9	-4%	2.8
Arkansas	$400	$385	-$15	-4%	2.5
California	$284	$337	$53	19%	4.4
Colorado	$344	$829	$485	141%	5.4
Connecticut	$936	$1,795	$859	92%	4.7
Delaware	$648	$761	$113	17%	2.9
Florida	$241	$138	-$103	-43%	1.6
Georgia	$425	$351	-$74	-17%	2.3
Idaho	$401	$783	$382	95%	4.4

Illinois	$529	$1,222	$693	131%	5.0
Indiana	$506	$1,013	$507	100%	4.6
Iowa	$528	$1,321	$793	150%	5.0
Kansas	$482	$852	$370	77%	4.1
Kentucky	$504	$632	$128	25%	3.0
Louisiana	$232	$187	-$45	-19%	2.4
Maine	$1,017	$1,841	$824	81%	3.4
Maryland	$636	$754	$118	19%	3.0
Massachusetts	$969	$1,874	$905	93%	4.5
Michigan	$605	$1,669	$1,064	176%	6.1
Minnesota	$679	$1,963	$1,284	189%	5.1
Mississippi	$298	$298	$0	0%	2.9
Missouri	$561	$791	$230	41%	3.0
Montana	$509	$1,345	$836	164%	4.9
Nebraska	$487	$1,003	$516	106%	4.2
Nevada	$283	$365	$82	29%	3.3
New Hampshire	$990	$1,923	$933	94%	3.9
New Jersey	$575	$1,084	$509	89%	4.9
New Mexico	$258	$462	$204	79%	5.6
New York	$749	$1,439	$690	92%	4.3
North Carolina	$424	$392	-$32	-8%	2.6
North Dakota	$619	$1,731	$1,112	180%	4.8
Ohio	$559	$994	$435	78%	4.0
Oklahoma	$355	$453	$98	28%	3.4
Oregon	$538	$601	$63	12%	3.1
Pennsylvania	$669	$1,031	$362	54%	3.6
Rhode Island	$937	$1,705	$768	82%	4.4
South Carolina	$346	$335	-$11	-3%	2.9
South Dakota	$534	$1,461	$927	174%	5.2
Tennessee	$327	$425	$98	30%	3.6
Texas	$254	$254	$0	0%	3.0
Utah	$407	$655	$248	61%	3.9
Vermont	$993	$2,320	$1,327	134%	4.5
Virginia	$512	$564	$52	10%	2.9
Washington	$595	$649	$54	9%	2.9
West Virginia	$414	$631	$217	52%	3.7
Wisconsin	$590	$1,729	$1,139	193%	5.1
Wyoming	$569	$1,148	$579	102%	4.0
		Average	$411	66%	3.8
		Median	$305	69%	3.9

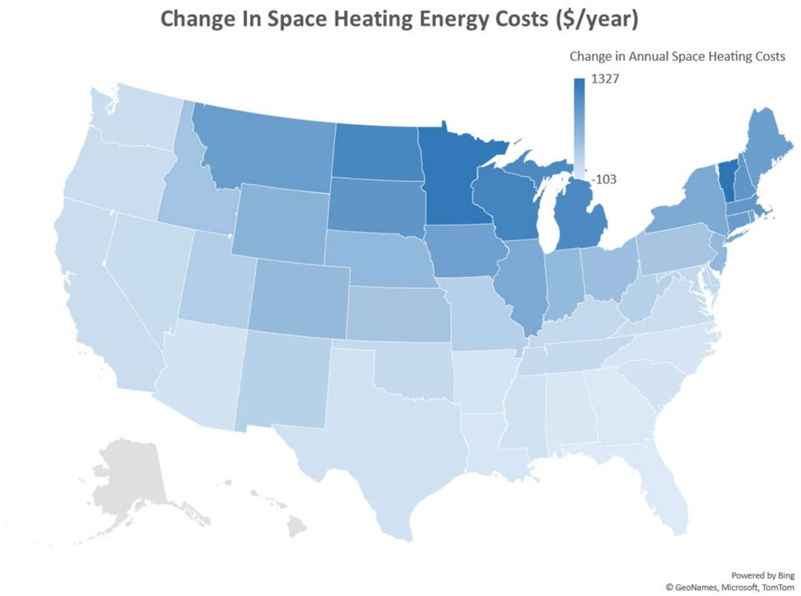


Figure 28: US Space Heating Annual Cost Changes with Electric Space Heating

Natural Gas and Electric Space Heating GHG Comparisons

Table 4 provides a state-level summary of the GHG impact of switching from residential gas space heating to electric space heating under two different winter power generation emission rates: winter marginal and winter average. Using the Winter Marginal Emission Rate, the median change in emissions is an increase of 32.8%, with increases occurring in 29 states (60% of the 48 states). Using the Average Winter Emission Rate, the median change in emissions is -23.4%, with increases in 16 states (33% of the 48 states).

Table 4: State-Level Gas and Electric Space Heating CO_2 Emissions Comparison

	Gas Annual CO_2 Emissions (1000 lbs)	Electric Winer Average Annual CO_2 Emissions (1000 lbs)	% Change in Space Heating Annual CO_2 Emissions (Winter Average)	Electric Winter Marginal Case Annual CO_2 Emissions (1000 lbs)	% Change in Space Heating Annual CO_2 Emissions (Winter Marginal)
Alabama	3.11	1.98	-36.3%	1.95	-37.4%
Arizona	1.99	1.38	-30.7%	1.63	-18.1%
Arkansas	4.43	4.83	9.0%	8.33	88.0%
California	2.14	0.85	-60.3%	0.85	-60.3%
Colorado	6.18	8.97	45.1%	15.36	148.6%
Connecticut	7.77	4.41	-43.2%	7.52	-3.2%
Delaware	6.43	4.49	-30.2%	6.36	-1.1%
Florida	1.63	1.1	-32.5%	1.39	-14.7%
Georgia	3.55	2.42	-31.8%	5.22	46.9%
Idaho	6.96	1.76	-74.7%	2.36	-66.1%

Illinois	8.17	7.18	-12.1%	11.99	46.7%
Indiana	7.89	13.89	76.0%	16.34	107.1%
Iowa	8.63	9.06	5.0%	65.64	660.6%
Kansas	6.28	5.68	-9.6%	14.45	130.1%
Kentucky	6.47	10.65	64.6%	9.99	54.5%
Louisiana	2.45	1.77	-27.8%	1.36	-44.3%
Maine	8.69	2.89	-66.7%	6.60	-24.1%
Maryland	6.32	5.18	-18.0%	39.77	529.3%
Massachusetts	8.27	7.52	-9.1%	10.87	31.4%
Michigan	9.28	11.52	24.1%	18.54	99.8%
Minnesota	10.9	13.49	23.8%	35.35	224.3%
Mississippi	3.23	2.43	-24.8%	2.91	-9.9%
Missouri	7.22	10.8	49.6%	7.66	6.1%
Montana	9.33	13.34	43.0%	16.21	73.8%
Nebraska	8.08	11.57	43.2%	29.65	266.9%
Nevada	3.19	2.49	-21.9%	2.49	-21.9%
New Hampshire	8.41	3.23	-61.6%	11.28	34.1%
New Jersey	6.91	3.01	-56.4%	3.01	-56.4%
New Mexico	4.34	4.99	15.0%	10.19	134.7%
New York	7.07	3.79	-46.4%	6.80	-3.8%
North Carolina	4.09	2.69	-34.2%	4.77	16.6%
North Dakota	11.56	6.07	-47.5%	106.46	820.9%
Ohio	7.94	10.92	37.5%	12.61	58.8%
Oklahoma	4.76	3.39	-28.8%	8.89	86.7%
Oregon	6.21	1.66	-73.3%	1.66	-73.3%
Pennsylvania	7.46	6.76	-9.4%	8.41	12.7%
Rhode Island	7.83	6.94	-11.4%	8.99	14.8%
South Carolina	3.06	1.69	-44.8%	2.65	-13.2%
South Dakota	10.6	4.88	-54.0%	73.48	593.2%
Tennessee	3.76	2.09	-44.4%	2.09	-44.4%
Texas	2.68	2.15	-19.8%	5.20	94.1%
Utah	6.75	10.58	56.7%	10.58	56.7%
Vermont	9.24	0.15	-98.4%	0.15	-98.4%
Virginia	5.13	3.05	-40.5%	3.05	-40.5%
Washington	7.17	1.29	-82.0%	1.29	-82.0%
West Virginia	6.02	11.13	84.9%	11.13	84.9%
Wisconsin	10.02	16.54	65.1%	23.12	130.7%
Wyoming	9.12	19.73	116.3%	19.73	116.3%
Median	6.83	4.66	-23.4%	8.37	32.8%
Average	6.43	6.01	-10.9%	14.09	84.5%

Electrification Impact on Residential Electricity Demand

Table 5 shows results of the estimated impact of residential electrification on peak winter demand and its comparison to the projected summer electricity peak. Across these forty-eight states, the winter peak for electricity would be 175% of the future summer peak (while not shown in the table, this would be about 195% of the current summer peak electricity demand). Winter peaks occur in 45 of the 48 states (94%).

Table 5: State-Level Residential Gas and Electric Space Heating Energy Demand Comparison

	Current Natural Gas January 2021 State Demand (MMkWh)	Current Electricity January 2021 State Demand (MMkWh)	Future Electricity January State Demand (MMkWh)	Future Electricity August 2021 State Demand (MMkWh)	Future Winter/Summer Peak Ratio
Alabama	2,084	3,165	4,086	3,498	117%
Arizona	2,464	2,596	3,868	4,839	80%
Arkansas	2,118	1,910	2,902	2,077	140%
California	20,533	7,578	15,395	12,297	125%
Colorado	6,962	1,789	5,750	2,727	211%
Connecticut	2,931	1,278	2,745	1,505	182%
Delaware	723	497	838	569	147%
Florida	904	9,836	10,017	13,906	72%
Georgia	7,441	5,697	8,905	6,989	127%
Idaho	1,553	963	1,808	850	213%
Illinois	21,470	4,189	16,484	6,766	244%
Indiana	7,556	3,355	7,426	3,876	192%
Iowa	3,495	1,484	3,642	1,626	224%
Kansas	3,608	1,204	3,131	1,832	171%
Kentucky	2,992	2,841	4,339	2,879	151%
Louisiana	2,041	2,876	3,772	3,584	105%
Maine	167	468	570	446	128%
Maryland	4,706	2,940	5,139	3,082	167%
Massachusetts	6,456	1,951	5,294	2,460	215%
Michigan	16,860	3,149	12,623	4,868	259%
Minnesota	7,100	2,215	7,076	2,781	254%
Mississippi	1,158	1,816	2,331	2,094	111%
Missouri	6,338	3,653	7,000	4,136	169%
Montana	996	574	1,223	537	228%
Nebraska	2,012	995	2,197	1,119	196%
Nevada	2,452	954	2,258	2,104	107%
New Hampshire	428	472	722	500	144%
New Jersey	13,196	2,628	8,935	4,337	206%

New Mexico	2,188	670	1,671	882	190%
New York	23,624	4,684	17,517	7,142	245%
North Carolina	4,992	6,209	8,367	6,569	127%
North Dakota	628	541	980	424	231%
Ohio	15,608	5,234	13,503	6,295	215%
Oklahoma	3,872	2,234	4,097	2,944	139%
Oregon	2,104	2,062	2,943	1,758	167%
Pennsylvania	13,890	5,787	12,936	6,108	212%
Rhode Island	1,077	288	824	425	194%
South Carolina	2,274	3,054	4,047	3,534	115%
South Dakota	642	505	918	496	185%
Tennessee	4,921	4,434	6,719	4,615	146%
Texas	11,684	13,455	18,785	19,235	98%
Utah	3,677	901	2,771	1,363	203%
Vermont	195	223	343	216	158%
Virginia	5,076	5,252	7,575	4,709	161%
Washington	3,901	4,002	5,583	2,971	188%
West Virginia	1,485	1,347	2,098	1,005	209%
Wisconsin	7,285	2,156	6,663	2,726	244%
Wyoming	767	319	782	252	310%
				Median	175%
				Average	177%

Figure 29 and Figure 30 provide two graphical representations of the projected changes in residential winter and summer electricity demand under a broad-scale electrification scenario in individual states.

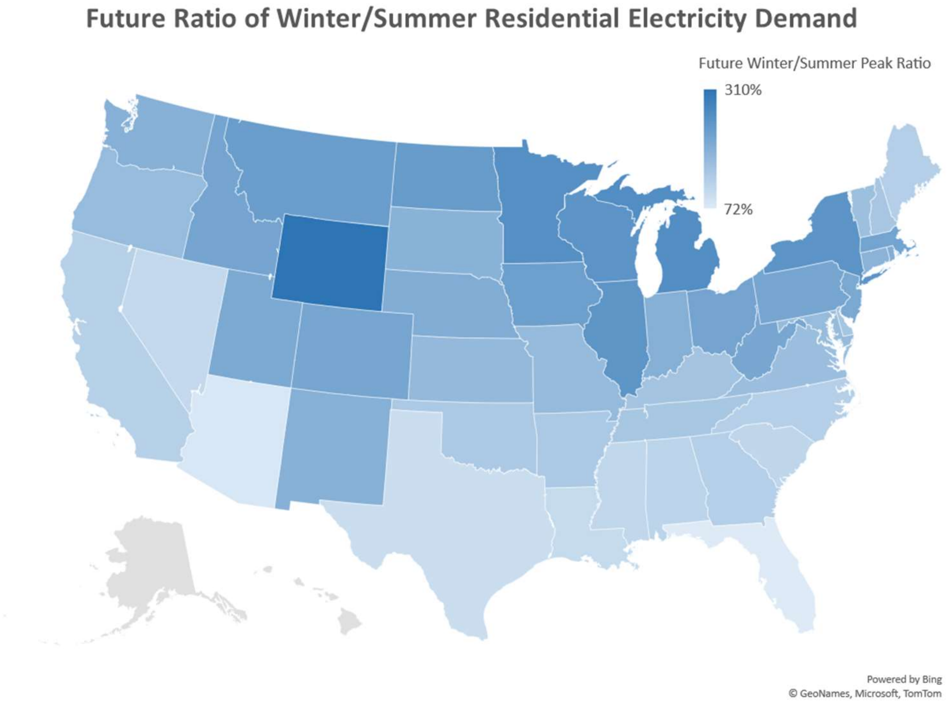


Figure 29: Projected Electrification Impact on Peak Winter/Summer Demand Ratio

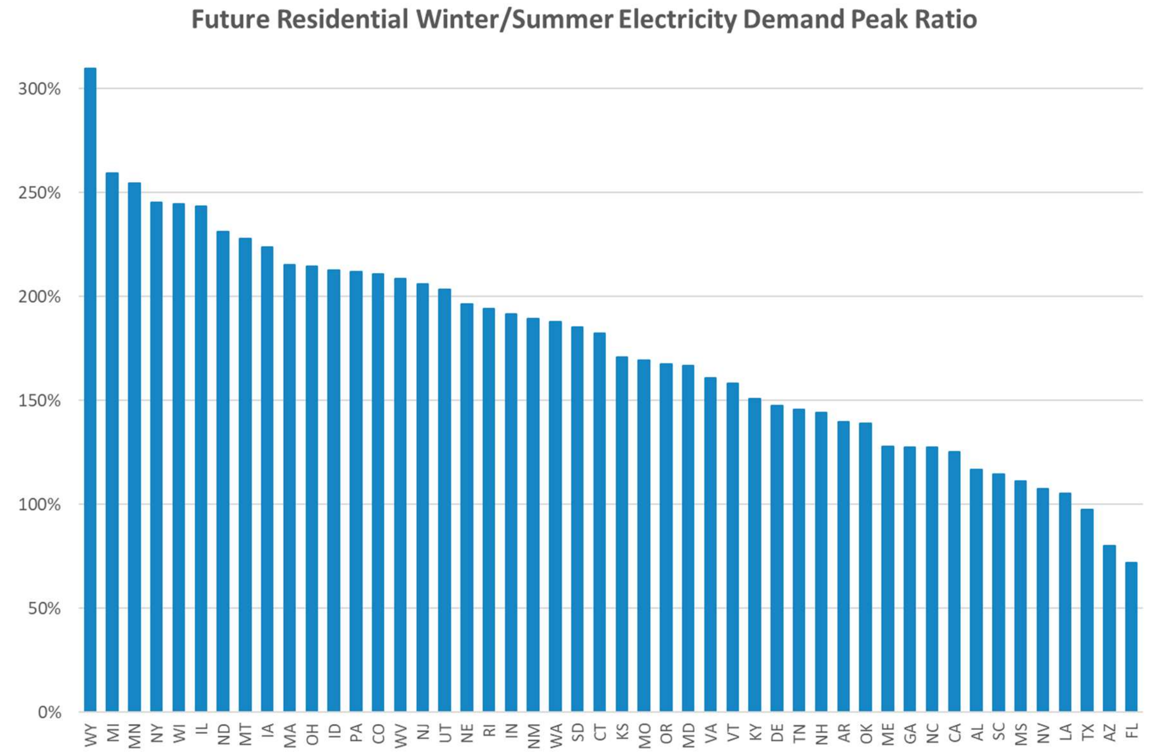


Figure 30: Impact of Electrification on Peak Winter Demand Compared to Summer Demand

Findings and Recommendations

This report focuses on residential space heating energy use, consumer energy cost, seasonal electric power generation considerations, GHG reduction factors, and projected future peak winter and summer demand under a potential residential electrification scenario in forty-eight states. Report information highlights the large degree of state-level diversity across the country in terms of space heating energy demand and facets of the power generation mix.

Findings of this report include:

- Average annual space heating energy cost increases of $411 per single-family home (66% increase) across the 48 states when shifting from gas to electric space heating, with increases occurring in 79% of the states
- Winter Marginal Emission Rates of CO_2 are 53.5% higher than the Spring Average Generation Rate (nominal baseload); increases in winter electricity demand are highly correlated to the Winter Marginal Emission Rates
- CO_2 emissions switching from gas to electric space heating results in a median 32.8%increase when using the Winter Marginal Emission Rate, with increases in 60% of the states; using the Winter Average Emission Rate, there is a -23.4% decrease in CO_2 emissions, with increases in 33% of the states
- Residential electrification would shift peak residential electricity demand to January (from August) in 94% of the states, with an average future winter residential electricity demand that is 175% of the future summer electricity demand

Report recommendations include:

- Important to factor in cold-weather temperature impacts on electric heat pump performance (including cold-climate models). There are two dimensions to this issue:
    - Consumer energy cost impacts with operating electric heat pumps at very cold temperatures (especially in circumstances when units require supplemental electric resistance heating to deliver adequate heat to the home)
    - Grid sizing (i.e., generation and transmission/distribution networks) on peak day, week, and month due to the non-linear increase in electricity consumption as temperatures decline
    - Consideration of using hybrid gas and electric heating system strategies than can help mitigate both consumer and grid sizing impacts
- Attention directed to factoring in Winter Marginal Generation Rate (CO_2 emission rates) for the mix of power plants that operate on a seasonal basis to meet additional space heating loads
    - In most states, these are dominated by firmly dispatchable power generation plants such as combined-cycle gas generation – having serious implications in terms of capturing real-world GHG reductions with electric space heating
    - Efforts to decarbonize plants such as these using renewable gas and/or CO2 capture should be considered an elemental part of space heating GHG reduction plans

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Appendix A: Energy Planning Analysis Tool (EPAT) State-Level Detailed Report Example (Illinois)

Illinois winter average

Energy Planning Analysis Tool

Building Location and Configuration

State:	Illinois	Population:	12,830,630	Total State Home:	4,757,452

State Residential Electric Houses

Included?	House Type	Number of Units	Average Size (ft2)	Number of People per Unit
	Moblile	0	0	3
x	Single Fam. Detached	119,508	1,733	3
	Single Fam. Attached	14,500	1,360	3
	Apt. Building 2 to 4 units	40,148	878	3
	Apt. Building 5+ units	324,072	706	3
	All Residential Electric Houses	119,508	1,733	3

State Energy Price *

Electric Price (Cents/kWh)	Natural Gas Price ($/Therm)	Renewable Natural Gas Price ($/Therm)	Propane Price ($/Gal)	Renewable Propane Price ($/Gal)
13.04	0.77	3.00	1.45	3.50

*Note: EIA 2020 state annual prices

Select Building Configurations

Single House

Equipment Cost Basis: Retrofit

		Baseline	Alternative
Included?	Application	Equipment and Appliances	Equipment and Appliances
x	Space Heating	Natural Gas, AFUE 94% Electric Consumption: 40 (kWh) Gas Consumption: 596 (Therm) Installed Cost: 2,527 $/Unit +3.86 $/kBtuh Unit Capacity: 90 kBtuh	16 SEER /9.0 HSPF Heat Pump Electric Consumption: 8,923 (kWh) Gas Consumption: 0 (Therm) Installed Cost: 3,873 $/Unit +42.00 $/kBtuh Unit Capacity: 100 kBtuh
	Space Cooling	13 SEER(11.07 EER) A/C Electric Consumption: 502 (kWh) Gas Consumption: 0 (Therm) Installed Cost: 2,588 $/Unit +42.00 $/kBtu Unit Capacity: 36 kBtuh	16 SEER /9.0 HSPF Heat Pump Electric Consumption: 395 (kWh) Gas Consumption: 0 (Therm) Installed Cost: 0 $/Unit +0.00 $/kBtu Unit Capacity: 36 kBtuh
x	HVAC Blower	Electric Consumption: 493 (kWh)	Electric Consumption: 448 (kWh)
	Water Heating	Natural Gas EF 0.62 - Min. Eff. Storage Electric Consumption: 0 (kWh) Gas Consumption: 222 (Therm) Installed Cost: 728 $/Unit +10.00 $/gal Unit Capacity: 60 Gal	Electric Resistance EF, 0.95 Electric Consumption: 4,244 (kWh) Gas Consumption: 0 (Therm) Installed Cost: 591 $/Unit +3.50 $/gal Unit Capacity: 60 Gal
	Lighting &	Electric Consumption: 2,513 (kWh)	Electric Consumption: 2,513 (kWh)

	Plug-in Loads		
	Cooking Range	Gas Standard Electric Consumption: 0 (kWh) Gas Consumption: 31 (Therm) Installed Cost: 823 $/Unit	Electric Standard EF 0.74 Electric Consumption: 0 (kWh) Gas Consumption: 0 (therm) Installed Cost: 923 $/Unit
	Refrigerator	How many: 1 Electric Consumption: 0 (kWh)	How many: 1 Electric Consumption: 0 (kWh)
	Dishwasher	How many: 1 Electric Consumption: 172 (kWh)	How many: 1 Electric Consumption: 172 (kWh)
	Washer	How many: 1 Electric Consumption: 88 (kWh)	How many: 1 Electric Consumption: 0 (kWh)
	Clothes Dryer	Gas Standard EF 2.75 Electric Consumption: 76 (kWh) Gas Consumption: 35 (Therm) Installed Cost: 1,000 $/Unit	Electric Standard EF 3.1 Electric Consumption: 971 (kWh) Gas Consumption: 0 (Therm) Installed Cost: 760 $/Unit
	Electrical Service Upgrade	No Electrical Upgrade 0 $/house	No Electrical Upgrade 0 $/house
	Photovoltaic	PV Installed : No PV Array Size : 0 (kW) Battery Installed: No Battery Size: 0 (kWh) Economics: Net Metering Electricity Retail Rate Multiplier : 0 Direct Solar Offsets: 0 (kWh) Battery Offsets: 0 (kWh) Electricity Exported to Grid: 0 (kWh) PV Cost: 0 $/kW Battery Cost: 0 $/kWh Total Cost: 0 $/System	PV Installed : No PV Array Size : 0 (kW) Battery Installed: No Battery Size: 0 (kWh) Economics: Net Metering Electricity Retail Rate Multiplier : 0 Direct Solar Offsets: 0 (kWh) Battery Offsets: 0 (kWh) Electricity Exported to Grid: 0 (kWh) PV Cost: 0 $/kW Battery Cost: 0 $/kWh Total Cost: 0 $/System
	Micro CHP	None Electric Reduced: 0 (kWh) Electric Export to Grid: 0 (kWh) NG Building Used Reduction: 0 (therm) mCHP NG Consumption: 0 (therm) Installed Cost: 0 $/Unit + 0 $/kW	None Electric Reduced: 0 (kWh) Electric Export to Grid: 0 (kWh) NG Building Used Reduction: 0 (therm) mCHP NG Consumption: 0 (therm) Installed Cost: 0 $/Unit + 0 $/kW

Source Energy Factors And Composite Emission Factors

Geographic Area:	State: Illinois
Plant Level Database:	All Plants
eGrid Database:	2020 data
eGrid Level:	eGRID 2020 data State database
Renewable Conversion Efficiency:	Captured

Source Energy Factors

	Electric	Natural Gas	Renewable Natural Gas	Propane	Renewable Propane
Btu/Btu	3.13	1.09	1.28	1.15	1.27

Composite Emission Factors

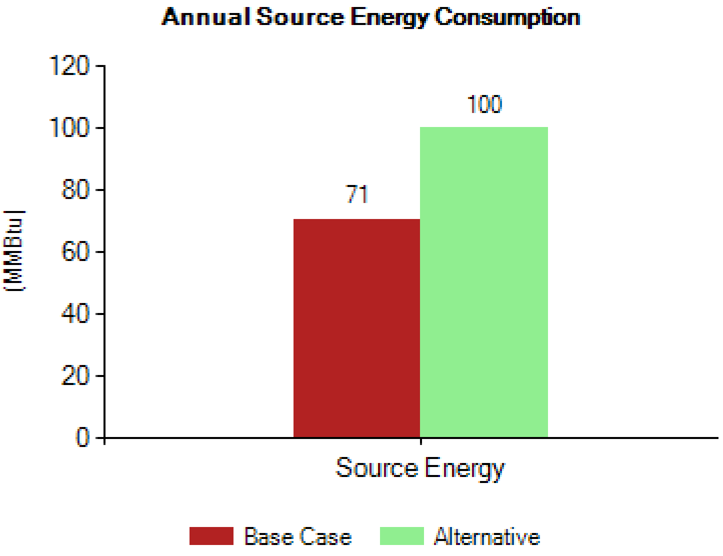
Energy Form	CO2	SO2	NOx	CH4	N2O	CO2e
Electricity (lb/MWh)	765.9	1.143	0.508	1.393	0.0100	807.5
Natural Gas (Building Used, lb/MMBtu)	130.2	0.029	0.172	0.605	0.0030	147.8
Renewable Natural Gas (Building Used, lb/MMBtu)	35.1	0.084	0.281	0.511	0.0030	50.3
Propane (lb/MMBtu)	163.2	0.055	0.225	0.079	0.0110	168.3
Renewable Propane (Building Used, lb/MMBtu)	43.5	0.101	0.281	0.013	0.0110	47.0
Natural Gas (mCHP NG Engine Used, lb/MMBtu)	137.2	0.029	1.892	1.468	0.0000	178.4
Natural Gas (mCHP Fuel Cell Used, lb/MMBtu)	128.9	0.028	0.055	0.603	0.0000	145.8

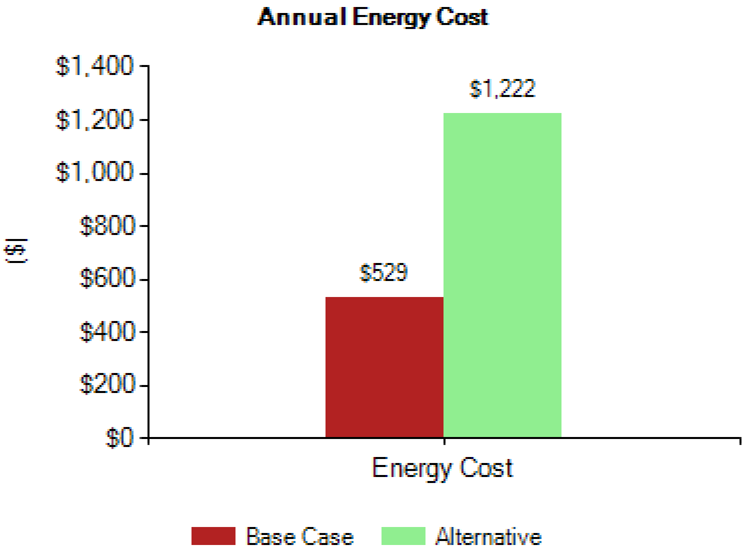
Source Energy and Emission Factors are calculated for IL: Energy conversion efficiency and specific emission data for electricity generated using fossil fuels and biomass are based on eGRID 2020 data State database. Electric distribution efficiency data are based on eGRID 2020 data State database. Electricity generation fuel mix distribution data are based on user custom data All other default data are based on EIA, NREL, and ANL (GREET 1 2012) data sources.

Energy Consumption and Cost

	Energy	Annual Site Consumption	Annual Site Consumption	Annual Source Consumption	Annual Energy Cost	Equipment Invest Cost
			(MMBtu)	(MMBtu)	($)	($)
Baseline	Electricity (Total Building Used)	533 (kWh)	1.82	5.69	70	2,874
	Electricity Offset (Distributed Generation)	0 (kWh)	0.00	0.00	0	
	Electricity (Distributed Generation)	0 (kWh)	0.00	0.00	0	
	Natural Gas (Building Used)	596 (Therm)	59.60	64.96	459	
	Natural Gas (mCHP Used)	0 (Therm)	0.00	0.00	0	
	Renewable Natural Gas (Building Used)	0 (Therm)	0.00	0.00	0	
	Propane (Building Used)	0 (Gal)	0.00	0.00	0	
	Renewable Propane (Building Used)	0 (Gal)	0.00	0.00	0	
	Total		61.42	70.66	529	
Alternative	Electricity (Total Building Used)	9,371 (kWh)	31.97	100.08	1,222	8,073
	Electricity Offset (Distributed Generation)	0 (kWh)	0.00	0.00	0	
	Electricity (Distributed Generation)	0 (kWh)	0.00	0.00	0	
	Natural Gas (Building Used)	0 (Therm)	0.00	0.00	0	
	Natural Gas (mCHP Used)	0 (Therm)	0.00	0.00	0	
	Renewable Natural Gas (Building Used)	0 (Therm)	0.00	0.00	0	
	Propane (Building Used)	0 (Gal)	0.00	0.00	0	
	Renewable Propane (Building Used)	0 (Gal)	0.00	0.00	0	
	Total		31.97	100.08	1,222	

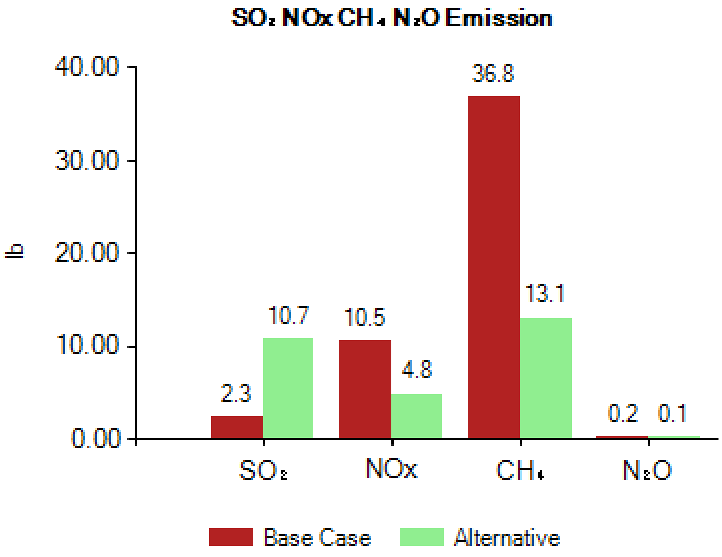
	Energy Cost Savings (Baseline-Alternative)	Equipment Invest Cost (Alternative-Baseline)	Simple Payback (Year)
	($)	($)	(Year)
Comparison	-693	5,199	Never

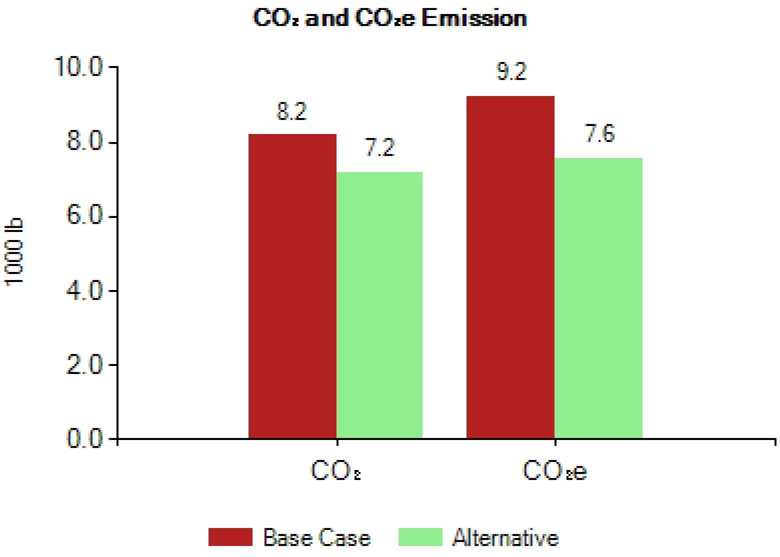




Annual Source Emissions

	SO2 (lb)	NOx (lb)	CO2 (1000 lb)	CH4 (lb)	N2O (lb)	CO2e (1000 lb)
Baseline	2.34	10.52	8.17	36.80	0.18	9.24
Alternative	10.71	4.76	7.18	13.05	0.09	7.57





Source Energy Factors And Composite Emission Factors

Geographic Area:	State: Illinois
Plant Level Database:	All Plants
eGrid Database:	2020 data
eGrid Level:	eGRID 2020 data State database
Renewable Conversion Efficiency:	Captured

Source Energy Factors

	Electric	Natural Gas	Renewable Natural Gas	Propane	Renewable Propane
Btu/Btu	3.03	1.09	1.28	1.15	1.27

Composite Emission Factors

Energy Form	CO2	SO2	NOx	CH4	N2O	CO2e
Electricity (lb/MWh)	657.2	0.976	0.446	1.206	0.0080	693.2
Natural Gas (Building Used, lb/MMBtu)	130.2	0.029	0.172	0.526	0.0030	145.6
Renewable Natural Gas (Building Used, lb/MMBtu)	35.1	0.084	0.281	0.507	0.0030	50.2
Propane (lb/MMBtu)	163.2	0.055	0.225	0.083	0.0110	168.5
Renewable Propane (Building Used, lb/MMBtu)	43.5	0.101	0.281	0.009	0.0110	46.8
Natural Gas (mCHP NG Engine Used, lb/MMBtu)	137.2	0.029	1.892	1.389	0.0000	176.2
Natural Gas (mCHP Fuel Cell Used, lb/MMBtu)	128.9	0.028	0.055	0.524	0.0000	143.6

Source Energy and Emission Factors are calculated for IL: Energy conversion efficiency and specific emission data for electricity generated using fossil fuels and biomass are based on eGRID 2020 data State database. Electric distribution efficiency data are based on eGRID 2020 data State database. Electricity generation fuel mix distribution data are based on user custom data All other default data are based on EIA, NREL, and ANL (GREET 1 2012) data sources.

Appendix B: Marginal Winter Generation Rate Calculation Example (Illinois)

The following example shows the calculation process and data used to calculate the Winter Marginal Generation Rate (CO_2 emissions per kWh) that is applicable to added January space heating demand; the example uses 2021 data for Illinois. The same method could be applied to analyzing space cooling load impacts by substituting August data for January.

The Winter Marginal Generation Rate is calculated by:

Marginal Winter Generation Rate =

$$\frac{[(\text{Winter Generation}*\text{Winter Seasonal Average Rate}) - (\text{Spring Generation}*\text{Spring Average Generation Rate})]}{\text{Marginal Winter Generation}}$$

In this example, DOE-EIA Illinois state-level generation data is used based on the January and April 2021 values (Table 6).

Table 6: Illinois DOE-EIA 2021 Power Generation Data (million kWh/month)

Illinois	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Gas, Oil, Coal	5656	5493	3687	3980	4731	6261	7186	7810	5397	4955	4851	4859
% Gas, Oil, Coal	35.1%	36.7%	27.5%	30.0%	31.5%	39.3%	42.6%	44.6%	36.7%	36.3%	32.4%	30.1%
% Non-Fossil	64.9%	63.3%	72.5%	70.0%	68.5%	60.7%	57.4%	55.4%	63.3%	63.7%	67.6%	69.9%
% Solar, Wind	9.8%	11.4%	16.4%	14.1%	11.2%	8.0%	5.8%	6.1%	10.6%	12.1%	14.6%	14.6%
Illinois : coal	4044	4123	2233	2807	3733	4223	4785	4695	3782	2970	2933	3185
Illinois : petroleum liquids	3	2	2	3	3	3	4	4	4	2	4	3
Illinois : natural gas	1609	1368	1452	1170	995	2035	2397	3111	1611	1983	1914	1671
Illinois : nuclear	8801	7735	7491	7370	8563	8349	8645	8589	7683	6990	7895	8883
Illinois : hydroelectric	12	9	10	11	11	11	11	12	10	10	10	11
Illinois : wind	1537	1643	2113	1770	1553	1146	807	895	1388	1514	2066	2257
Illinois : geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Illinois : biomass	35	30	34	32	34	34	33	33	33	33	32	34
Illinois : hydro pumped storage	0	0	0	0	0	0	0	0	0	0	0	0
Illinois : all solar	47	61	94	110	128	138	170	169	175	131	126	99
Illinois : other	23	16	22	21	22	21	22	22	21	11	23	22
Total:	16111	14987	13451	13294	15042	15960	16874	17530	14707	13644	15003	16165

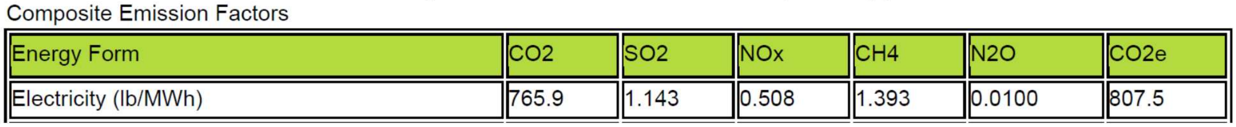
From this table, we use two generation amounts and calculate their difference:

- Spring Generation: 13,294 million kWh
- Winter Generation: 16,111 million kWh
- Marginal Winter Generation: 2,817 million kWh (Winter – Spring Generation)

This provides three of the five values needed for the Marginal Winter Generation Rate calculation.

We use the GTI EPAT software that relies upon the EPA eGRID statewide power plant emissions data to calculate the Winter and Spring Average rates using the power generation mix for the month of January and April, respectively. From this information, we use the Winter Average of 765.9 lb CO_2/MWh (347.4 g/kWh) and Spring Average 657.2 lb CO_2/kWh (298.1 g/kWh). This provides the additional two data points to complete the calculation.

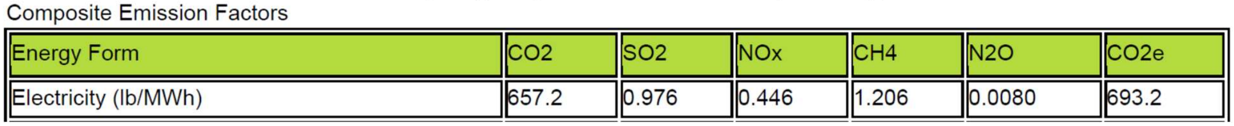
Average Winter Generation Rate (January)



Composite Emission Factors

Energy Form	CO2	SO2	NOx	CH4	N2O	CO2e
Electricity (lb/MWh)	765.9	1.143	0.508	1.393	0.0100	807.5

Average Spring Generation Rate (January)



Composite Emission Factors

Energy Form	CO2	SO2	NOx	CH4	N2O	CO2e
Electricity (lb/MWh)	657.2	0.976	0.446	1.206	0.0080	693.2

The Illinois Winter Marginal Generation Rate (g CO2/kWh):

$$= \frac{[16{,}111 \text{ million kWh} * 347.4 \text{ g } CO_2/\text{kWh} - (13{,}294 \text{ million kWh} * 298.1 \text{ g } CO_2/\text{kWh})]}{2{,}817 \text{ million kWh}} =$$

$$= 580.1 \text{ g } CO_2/\text{kWh}$$

When using this approach at a state level, it is important to identify if there is a large decrease in nuclear generation in April. That is a period in some cases when nuclear plants may be down for annual service. In such instances, an alternative spring of fall month should be chosen.

If specific monthly CO_2 power generation emissions and generation data are available, a simpler calculation process can be used:

Winter Marginal Generation Rate (g/kWh):

$$= \frac{(\text{January } CO_2 \text{ power generation emissions} - \text{April } CO_2 \text{ power generation emissions})}{(\text{January Generation} - \text{April Generation})}$$

These data can also be used to calculate the Winter Average and Spring Average Generation Rates by dividing the total CO_2 emissions in a month by the amount of generation.