

# Estimating Marginal Capacity Required to Replace Peak Natural Gas Loads in Minnesota Under Various Electrification Scenarios

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February 23rd, 2026

## Abstract

While Minnesota’s target of 100% carbon-free electricity by 2040 implies the eventual retirement of natural gas generators, the state uses nearly four times the gas for residential, commercial, and industrial heating. To address the possibility of electrifying heating loads, this work provides conservative estimates of the renewable and/or nuclear capacity needed to completely replace peak natural gas demand in Minnesota. This was accomplished in three steps. First, peak daily and monthly gas demand in the state were inferred from EIA and CenterPoint Energy data. Second, equivalent electric load was calculated using sector-wide COP values drawn from ResStock, ComStock, and other available literature for a range of potential electrification scenarios. Finally, the additional net summer capacity required to displace gas was found using January capacity factors for each non-fossil energy source. Consistent with existing literature, electrification with air-source heat pumps and other efficiency measures would still require around 2-3 times the state’s current generating capacity to meet peak month, and 4-5 times for peak day. These estimates were designed as conservative minimums for 100% electrification; they neglect transmission and distribution losses and electrification requirements of propane and fuel oil, including their downward effects on peak gas demand via gas curtailment.

## 1 Introduction

In the last five years, Minnesota introduced a sweeping array of policies designed to reduce carbon emissions and improve resource efficiency. In 2021, the Natural Gas Innovation Act (NGIA) enabled public utilities to implement a portfolio of pilot programs to reduce greenhouse gas emissions [1, 2]. In 2023 and 2024, targets for reductions in site-energy consumption for commercial and residential building codes were set to 80% and 70% of 2006 levels by 2036 and 2038 respectively [3, 4]. Additionally, in 2023, Minnesota joined a number of states imposing targets for clean power generation, setting 2040 as a deadline for establishing a 100% carbon-free grid [5, 6].

Despite these goals, the state has yet to finalize its “strategy map” for reducing demand for building and industrial heat supplied by natural gas and other fossil fuels [7]. While electrification measures such as heat pumps are a promising approach to reduce emissions in much of the country, the feasibility and impact of shifting these loads onto the grid is not fully understood in cold climates and comes with profound implications for Minnesota’s economic and energy policy.

Fortunately, high fidelity tools are now available to support policymakers in understanding the impacts of electrification. First introduced in 2001, DOE’s EnergyPlus building modeling software [8] forms the nucleus of ComStock [9] and ResStock [10], projects by NLR/NREL to sample and simulate the building stock in all 50 states. Aggregated by state, sector, and building type, these packages provide calibrated end-use profiles for the current building stock throughout the course of the year, with and without a wide range of electrification measures.

These large-scale simulation tools have become integral to development of energy policy in the United States. Since 2015, EnergyPlus simulations have become the standard benchmark for state and national code-making bodies in assessing the energy savings and cost-effectiveness of new residential [11, 12] and commercial [13, 14] building energy codes. ComStock and ResStock have also been adapted to investigate the economic potential of electrification measures [15, 16, 17], for example by simulating building demand

under long-term energy growth rates predicted by EIA [15]. Particularly important to this work, Wilson et al. employed ComStock and ResStock to evaluate the economics of three tiers of residential air-source heat pumps (ASHPs) with and without building retrofits for a number of price and subsidy scenarios [17]. Notably, they found large regional variation in ASHP economics, with cold climate states like Minnesota requiring substantial subsidies for the majority of homes to yield positive net-present value with cold-climate ASHPs (ccASHPs): \$2000 for all-electric homes and \$13,500 for those with gas [18]. As cold-climate performance is essential for reducing winter peak requirements in a fully-electrified grid, these results suggest heat pumps may not ease electrification requirements in Minnesota to the same degree as other states.

The importance of resolving seasonal (winter) variation in electrified heating loads was highlighted in 2022 by Buonocore et al. [19]. Using monthly EIA energy data from 2010 to 2020, the authors estimated the amount of renewables required to replace fossil fuels for the United States as a whole. To account for potential electrification measures, they applied various benchmark COP values to heating loads to reflect increasing efficiency of electrification. In this work, such values are defined within each sector as

$$\text{COP}_s = \frac{E_{\text{gas}}}{E_{\text{elec}}}, \quad (1)$$

where  $E_{\text{elec}}$  is the electric energy required to replace gas heat  $E_{\text{gas}}$  with a particular electrification measure. In Buonocore et al., these COP values varied from basic resistive electric heating (COP 1), to ASHPs (COP 2), ground-source heat pumps (GSHP, COP 4), and network-GSHP (COP 6). In all cases, the authors found peak electric load would shift from summer to winter, with decreasing January peaks with greater COP. To meet these demands would require between 4.5 (COP 6) and 28 (COP 1) times the nation’s current wind capacity. With solar, electrification would require between 36 (COP 6) and 303 (COP 1) times current capacity. These results underscore the need to consider electrification requirements in tandem with potential efficiency measures, such as heat pumps.

However, Buonocore et al. cautioned that these COP values reflect benchmarks for overall sector electrification, not actual heat pump performance. In reality, heat pumps cannot practically be used in 100% of heating applications. For example, a 2025 study in Minnesota found industrial heat pump technical potential was limited to 32% of heating loads. Additionally, Buonocore et al. did not account for seasonal variation in heat pump performance and considered only peak heating month, not peak day. For Minnesota, these limitations suggest  $\text{COP}_s$  are likely much lower than equipment COP, especially during peak heating days when extreme temperatures greatly reduce ASHP COP or require resistive backup heating. Hence, renewable requirements may be considerably greater than previously predicted.

This study aimed to quantify these dynamics, building on Buonocore et al. by incorporating end-use profiles from ComStock and ResStock to obtain average and peak  $\text{COP}_s$  values specific to January in Minnesota for five levels of electrification. Likewise,  $\text{COP}_s$  values for Minnesota’s industrial gas use were estimated using the recent MN CARD study [20]. These scenarios were then applied to historic daily and monthly peak gas loads, obtained by correlating Monthly EIA data against CenterPoint Energy gas throughout data. Together, these enabled more accurate estimates of renewable requirements for full electrification of Minnesota’s natural gas supply.

## 2 Methods

Analysis for this work relied on EIA monthly gas and electric data for Minnesota and on COP values obtained for each sector from literature and NLR datasets. Nonpublic data from CenterPoint energy was used to estimate peak gas day from public monthly data. Peak day and month calculations were performed from 2016 to 2026, with the breakdown of gas by sector for 2025 and 2026 taken from EIA data for 2024.

### 2.1 Peak Gas Demand

Minnesota monthly gas consumption data was acquired from EIA Open Data API [21] for 2016-2024, with gas volume for residential (N3010MN2), commercial (N3020MN2), industrial (N3035MN2), electric (N3045MN2), and transportation (NA1570\_SMN\_2) sectors checked against totals (N3060MN2) and converted to heating values by multiplication with gas caloric data (NGA\_EPG0\_VGTH.SMN\_BTUCF). Yearly maximums (January) were retained for peak gas analysis.

To estimate daily gas usage for the state, throughput data for CenterPoint Energy, the state’s largest gas utility, was compared on a monthly basis to EIA figures. This monthly ratio was then applied to all days within each month, scaling up CenterPoint’s daily throughput to approximate the state’s total. As expected, the correlation between CenterPoint and Minnesota gas demand was strong ( $R^2 > 0.9$ ). Finally, daily total gas was divided into each sector proportional to their monthly component within the EIA dataset. Peak day was then selected from each year, in all but one case occurring in January. For consistency, 2021’s peak in December was removed from the dataset to ensure all peak days fell approximately one year apart, sometime in January. While this correlation method may not yield true peak day values, they are reasonable proxies for estimating peak day requirements.

The peak month and day data for Minnesota is given in Figure 1, and is broken down by sector. Peak gas increased modestly from the beginning of the dataset in 2016 to the end in 2026. Crucially, daily throughput for peak day exceeded peak month by around 1 million Dth’s, or approximately 50%. Sector breakdown reveals residential and commercial consumption take up the majority of gas use. There are few clear trends in sector gas consumption, with the exception of gas used for electric generation, which has increase for peak months in the last decade.

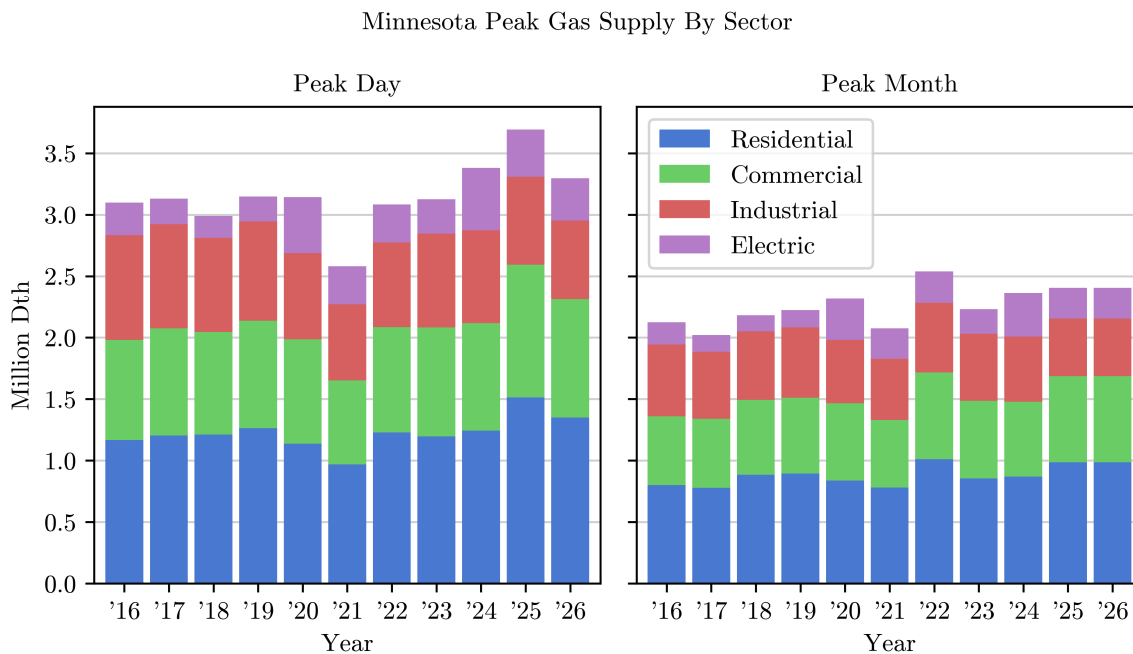


Figure 1: Daily and monthly peak gas consumption in Minnesota. For comparison, peak month (January) values are shown as per-day values (divided by 31).

## 2.2 Sector COP Values

The novel contribution of this work lies in selecting seasonally and geographically appropriate  $COP_s$  values for different levels of electrification measures. Unlike in Buonocore et al.,  $COP_s$  values were not selected as fixed reference points but depend on the performance of electrification measures at cold temperatures as derived from best available literature for the state of Minnesota in January for each sector.  $COP_s$  values and sources are summarized in Table 1.

Five levels of measures were defined: *No Measures*, *Basic*, *Advanced*, *Advanced+*, and *Maximum*. For *No Measures*, electric resistance was assumed for all sectors, assuming  $AFUE = 90\%$  for all gas equipment (electric heating was treated as 100% efficient). For *Basic* and both *Advanced* categories, minimum efficiency and high-performance heat-pump equipment were selected respectively. To these, *Advanced+* added envelope or other secondary efficiency measures which further improve  $COP_s$ . Lastly, the *Maximum* category applied

Table 1: Descriptions of efficiency measures for each sector. Final sector COP values are highlighted in gray.

	No Measure	Basic	Advanced	Advanced+	Maximum	
Res.	ResStock ID	-	(1)	(3)	(13)	(15)
	Description	Elec. Res.	Min. Eff. ASHP	ccASHP	ccASHP+Env.	GSHP
	HP Specs.	-	HSPF1 9.2	HSPF1 13	HSPF1 13	EER 20.5
			50%, 5°F	90%, 5°F	90%, 5°F	COP 4
	Other Measures	-	-	-	Various <sup>1</sup>	Various <sup>1</sup>
	Peak Day COP <sub>s</sub>	1.11	1.23	1.28	1.49	4.03
Peak Month COP <sub>s</sub>	1.11	1.12	1.98	2.50	3.31	
Com.	ComStock ID	-	(15)	(55)	(58)	(63)
	Description	Elec. Res.	HP Boiler	+ HP RTU	+ HP RTU	GSHP <sup>4</sup>
	HP Specs.	-	COP 2.85, 47°F	COP 2.11, 0°F	COP 2.11, 0°F	COP > 3
			$T > -5^\circ\text{F}$			
	Other Measures	-	-	LEDs	Various <sup>2</sup>	Envelope <sup>3</sup>
	Peak Day COP <sub>s</sub>	1.11	1.07	1.03	1.25	3.53
Peak Month COP <sub>s</sub>	1.11	0.94	1.15	1.61	3.08	
Ind.	Description	Elec. Res.	4.7% ASHP	32% ASHP	32% ASHP	32% GSHP
	HP Specs.	-	COP 2	COP 2	COP 2	COP 4
	COP <sub>s</sub>	1.11	1.12	1.32	1.32	1.46
Elec.	Thermal Eff.	0.28 - 0.33	0.28 - 0.33	0.28 - 0.33	0.28 - 0.33	0.28 - 0.33
	COP <sub>s</sub>	3.03 - 3.57	3.03 - 3.57	3.03 - 3.57	3.03 - 3.57	3.03 - 3.57
Trans.	Thermal Eff.	0.35	0.35	0.35	0.35	0.35
	COP <sub>s</sub>	2.86	2.86	2.86	2.86	2.86

<sup>1</sup> *Light Touch Envelope + Full Appliance Electrification*: IECC 2021 Attic Floor Insulation, 30% Reduction in ACH50, HPWH, Energy Star dryer, Induction Cooktop, Electric Pool heating

<sup>2</sup> *Demand Control Ventilation + Energy Recovery + Economizers*: Energy Recovery in CZ-6B only, Economizers on all buildings, DCV only applied for certain commercial buildings

<sup>3</sup> *High Efficiency Envelope Package*: Window Replacement (0.25-0.48 U-factor), Exterior Wall Insulation (R-21 in CZ-6), Roof Insulation (R-33 in CZ-6)

<sup>4</sup> Includes Central Hydronic GHP, Packaged GHP, and Console GHP

ground-source heat pumps with envelope improvements, representing the maximum foreseeable electrification measures that could be adopted. These groupings represent approximate levels of electrification with the aim of broadly describing the sensitivity of grid capacity requirements to increase electrification.

For residential and commercial sectors, ResStock (v2024.2) and ComStock (v2025.3) for Minnesota were used to obtain COP<sub>s</sub> directly from time-series data aggregated by building prototype, where  $E_{\text{gas}}$  was taken from the baseline simulation representing the current building stock, and the corresponding electrification  $E_{\text{elec}}$  found from results for each of the five measure levels. However, as these aggregations do not reveal which portion of electric energy came from gas electrification specifically, Equation 1 was approximated as a bulk value for electrification of all fossil fuels. Thus, propane and fuel oil in the baseline simulation were combined with gas to model  $E_{\text{gas}}$ . Then,  $E_{\text{elec}}$  for fossil fuels was estimated from the efficiency case by taking the total energy across all buildings and subtracting the electrical energy from the base case. While this does leave efficiency gains of existing electric homes (e.g. from improved insulation) attributed to gas electrification, this has the effect of making the resulting COP<sub>s</sub> values conservatively high, and the ultimate renewables requirements conservatively low.

For each electrification measure in ResStock and ComStock, COP<sub>s</sub> was calculated and averaged by temperature using ResStock and ComStock’s AMY 2018 data for Minneapolis. From this lookup table, COP<sub>s</sub> was evaluated for historical temperatures on 15 minute intervals using conditions at Minneapolis-Saint Paul Air-

port.  $COP_s$  for peak day and month were then reconstructed by a weighted average of heating-degree days over a given day or month.

Unfortunately, the same level of detail for industrial electrification is not yet available. For this sector, weighted average  $COP_s$  values were defined as

$$COP_s = \left[ \beta \left( \frac{AFUE}{COP} \right) + (1 - \beta) AFUE \right]^{-1} \quad (2)$$

where  $\beta$  is the fraction of gas load amenable to heat pumps, so that

$$E_{elec} = E_{gas} COP_s^{-1} = E_{gas} \beta \frac{AFUE}{COP} + E_{gas} (1 - \beta) AFUE \quad (3)$$

captures the required heat ( $E_{gas} AFUE$ ) split into the component applicable to heat pumps and the residual resistive heating load. Following the 2025 CARD study [20], the market potential  $\beta$  was set at current conditions (4.7%) for the *Basic* measure. For *Maximum* and both *Advanced* measures,  $\beta$  was set to the current theoretical limit (32%) of heat pump deployment. To represent a range of heat pump efficiencies, COP 2 was chosen for all measures except *Maximum*, where COP 4 was used.

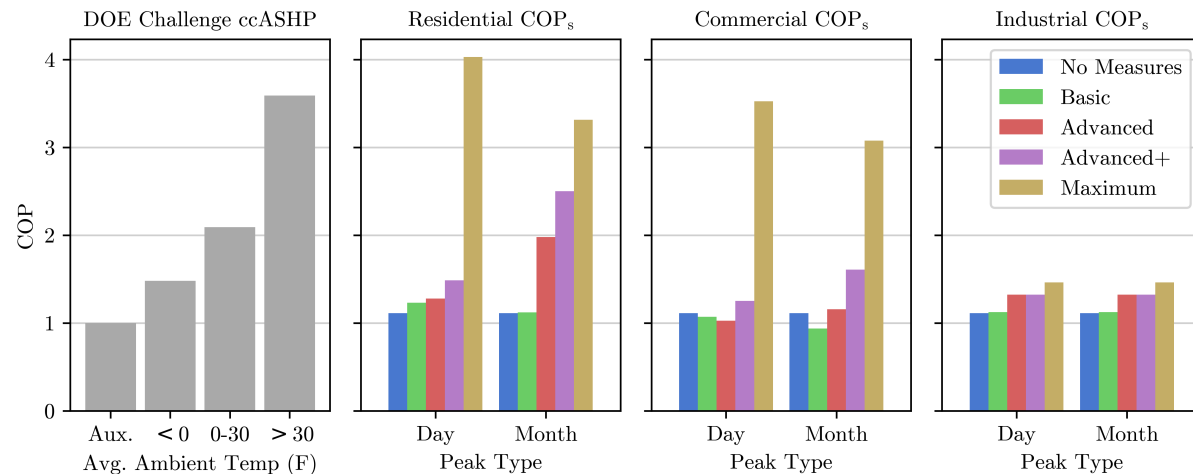


Figure 2: Final  $COP_s$  results for each sector, peak type, and electrification measure level (right), along with measured COP for ccASHP equipment by temperature range (left).  $COP_s$  taken by year of peak conditions, 2025 for peak day and 2022 for peak month.

For electrification of power generation, thermal efficiencies  $\eta$  for gas generators were solved directly for each January by dividing EIA SEP values for generated electricity by gas delivered to the power sector.  $COP_s$  values for electric generation were then computed as this inverse of  $\eta$ ,  $COP_s$  between 3.03 and 3.57. Likewise,  $\eta$  for transportation gas, a very small component of gas demand, was approximated as 35%.

### 2.3 Marginal Capacity Requirements

By dividing monthly and daily peak gas consumption  $E_{gas}$  in Section 2.1 by  $COP_s$  in Section 2.2, the equivalent electric energy  $E_{elec}$  was obtained. The marginal electric capacity required to meet this load was found by dividing monthly and daily  $E_{elec}$  by both their respective hours and the January capacity factor of the relevant technology (solar, nuclear, and wind). For solar and wind, monthly capacity factors were averaged from EIA data between 2016 and 2024. Given Minnesota's existing nuclear fleet is not representative of any future nuclear power plants installed, a standard capacity factor of 90% was used to estimate capacity requirements.

### 3 Results

The final power requirements for replacement of gas are shown in Figure 3 for each level of efficiency improvements. The additional power required for each sector are differentiated with colors, matching those in Figure 1. It is readily apparent that electric power generation is only a small fraction of electric energy required to replace gas, typically less than 5%. Additionally, while electric requirements for meeting peak month decline steadily with more advanced electrification measures, the same trend is not observed for peak day, where only measures with envelope improvements and/or GSHPs enable substantial (> 10%) mitigation of loads.

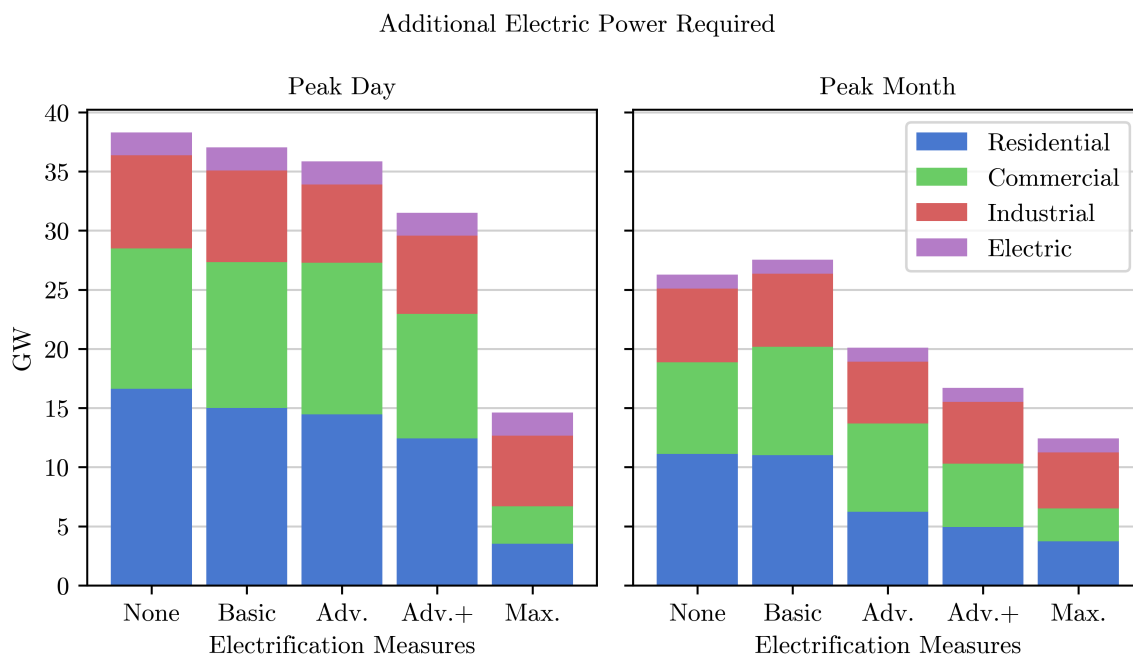


Figure 3: Additional daily electric energy required to electrify peak natural gas in Minnesota. Values obtained by averaging 2016 through 2024.

This phenomenon can be explained by the temperature extremes at peak day, where daily averages from 2016 to 2026 fell between  $-14^{\circ}\text{F}$  and  $-1^{\circ}\text{F}$ . In contrast, average temperatures for peak months fell between  $11^{\circ}\text{F}$  and  $22^{\circ}\text{F}$ . These disparate ranges bracket the typical switchover temperature for all but the most advanced ccASHPs, indicating ASHPs on peak day are operating mostly as resistive heaters. While envelope improvements in the *Advanced+* and *Maximum* measures do enable much large reductions, these are also independent of fuel source and could be applied to gas-fueled buildings. Furthermore, while the decline in annual HDDs in Minnesota from climate change is well-documented, there was no clear long-term trend in average temperatures on peak day, which are stochastic in nature. This indicates Minnesota’s low temperature extremes cannot be easily dismissed in long-term electrification planning.

Using the energy requirements in Figure 3, required power capacity of actual generation equipment was obtained specific to Minnesota. Summarized in Table 3, required solar, wind, and nuclear capacities were calculated using January capacity factors published by EIA. The resulting summer capacities were expressed as multiples of current capacity (2024, EIA’s most recent dataset). Capacities multiples for renewables (solar, wind, and hydropower) and carbon-free (renewables + nuclear) were also shown. Additionally, required power was shown as multiples of power generating stations, including the new MN Sherco Solar facility (910 MW), a Westinghouse AP1000 reactor (1.1 GWe), and the sum total of solar power under development in the state (11 GW). Lastly, rough estimates for required quantities of wind turbines and solar panels are given in the last row of Table 3.

Values in Table 3 demonstrate that Minnesota would need an unprecedented build-out of renewables

Table 2: Additional summer capacity required to replace January peak natural gas, by electricity source and level of electrification measure in Table 1. Values for Peak Month and Peak Day were selected from years 2022 to 2026.

		No Measures		Basic		Advanced		Advanced+		Maximum	
		Day	Month	Day	Month	Day	Month	Day	Month	Day	Month
Multiples of Current MN Capacity:	Electric Grid <sup>1</sup>	5.5	3.2	5.3	3.3	5.2	2.4	4.5	2.0	2.1	1.5
	Renewables	19	10	19	11	18	7.9	16	6.6	7.4	4.9
	Carbon Free	14	6.3	14	6.6	14	4.8	12	4.0	5.5	3.0
	Wind	24	12	24	13	23	9.5	20	7.9	9.3	5.9
	Solar	398	236	385	247	372	180	327	150	152	112
	Nuclear	58	16	56	17	55	12	48	10	22	7.6
Multiples of Power Plants	Sherco Solar <sup>2</sup>	495	340	479	356	464	260	407	216	189	161
	AP1000 Reactor <sup>3</sup>	38	26	36	27	35	20	31	16	14	12
	Solar Pipeline <sup>4</sup>	41	28	40	29	38	21	34	18	16	13
Power Units	Wind Turb. <sup>5</sup> /10 <sup>3</sup>	31	21	30	22	29	16	25	13	12	10
	Solar Panels <sup>6</sup> /10 <sup>6</sup>	1127	773	1090	810	1055	591	927	492	430	366

<sup>1</sup> Assuming current mix of January capacity factors

<sup>2</sup> 910 MW

<sup>3</sup> 1,100 MWe

<sup>4</sup> 11 GW in development

<sup>5</sup> 3.5 MW each

<sup>6</sup> Standard 400W panel

or nuclear, regardless of mitigating efficiency measures, to achieve full electrification of peak winter loads. Currently, the state is much closer to electrification via wind than solar, requiring around 10-20 times current capacity with wind compared to 150-400 times capacity for solar. Despite the fact that the state’s solar industry pipeline totals over 11 GW of planned projects (nearly 1/3 the total 33 GW required for peak day with no measures), solar’s poor capacity factor (< 10%) during peak loads in January calls for 20-30 times this capacity.

These results should be considered conservative estimates. First, this study does not attempt to quantify transmission and distribution losses (~ 7%) within a future electric grid with large-scale renewable expansion, nor does it account for losses associated with long-term energy storage technology which may be required to support renewables. Additionally, this study does not reflect electrification of propane and fuel-oil. While a relatively small share of overall heating demand, the peak day gas load used in this work is lowered by gas utilities implementing curtailment measures. This typically relies on customers switching to backup propane, not reducing overall heating demand. Therefore, a 100% electrification scenario would imply a higher peak day load than estimated in Section 2.1.

## 4 Conclusions

In this study, marginal renewable and/or nuclear capacity requirements to replace gas were estimated using peak day and month gas heating loads in Minnesota for five electrification scenarios. Required electric loads for each sector were obtained from gas counterparts via effective sector COP values in local January weather, dependent on both the real world performance of heat pump and efficiency measures and the degree of heat pump adoption possible. The capacity additions required to support this load was then obtained.

In general, COP<sub>s</sub> values demonstrate that full electrification with available electric-only ASHPs would have minimal impact on reducing peak loads from a COP<sub>s</sub> 1 baseline, particularly for peak day loads. This behavior was expected, both because heat pumps were not applied to 100% of the building stock in each sector (owing to the diverse requirements found within the building stock), and because ASHPs typically rely

on resistive heating at the extreme temperatures ( $T < -1$  °F) typical for peak heating days in Minnesota. On the other hand, universal ground-sourced heat pumps were found to reduce requirements, particularly for nuclear reactors, albeit the cost burden of such measures are considerable.

Though this work paints a more detailed picture of Minnesota’s renewable requirements under a policy of 100% electrification, it does not speak to how future technological advancements, in particular the growth of photovoltaics, may alter these numbers. From a purely mathematical standpoint, large multiples of required capacity should fall quickly during early stages of renewable growth, and then slow considerably as each remaining multiple reflects a larger absolute quantity of deployed capacity. Projecting these trends into the future is outside the scope of this work, but would require consideration of cost dynamics in addition to technical requirements, notably fuel cost and equipment economies of scale. In this vein, advanced concepts like seasonal energy storage could theoretically lower peak heating requirements, but are far from maturity. Lastly, this study could be made more precise by appealing to individual building models in ComStock and ResStock to compute  $COP_s$  exactly. Future studies should also investigate industrial electrification to develop more representative  $COP_s$  estimates.

## 5 Appendix

### 5.1 Replacement of Gas Heating Loads

Table 3: Additional summer capacity required to replace January peak natural gas heating load (excluding electricity generation). Adapted from methods in Table 3.

		No Measures		Basic		Advanced		Advanced+		Maximum	
		Day	Month	Day	Month	Day	Month	Day	Month	Day	Month
Multiples of Current MN Capacity:	Electric Grid	5.2	3.0	5.0	3.2	4.9	2.3	4.2	1.9	1.9	1.4
	Renewables	18	10	18	10	17	7.4	15	6.1	6.4	4.4
	Carbon Free	14	6.0	13	6.3	13	4.5	11	3.7	3.4	2.7
	Wind	23	12	22	12	22	8.9	19	7.3	7.7	5.3
	Solar	378	225	364	236	352	170	307	139	147	101
	Nuclear	55	15	53	16	52	12	45	9.5	7.4	6.9
Multiples of Power Plants	Sherco Solar	470	324	454	341	438	245	382	201	169	146
	AP1000 Reactor	36	25	34	26	33	19	29	15	13	11
	Solar Pipeline	39	27	37	28	36	20	32	17	14	12
Power Units	Wind Turb. / $10^3$	29	20	28	21	27	15	24	12	10	9.0
	Solar Panels / $10^6$	1069	738	1032	775	997	556	869	457	385	331

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