MINNESOTA'S SMARTER GRID

Pathways Toward a Clean, Reliable and Affordable Transportation and Energy System

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I. Background & Summary

This study offers pathways and analysis of how Minnesota (MN) could transition from its current energy system to one that is decarbonized by 80% (from 2005 level) by 2050 [***80x50***]. The decarbonization would include the entire economy and is assumed to include energy efficiency measures, electrification, and generation changes. The study will model the entire United States (US) portion of the Eastern Interconnection along with electricity trade between the US, Mexico and Canada. The primary purpose of the study is to determine how Minnesota can meet the goals of *80x50* under various scenarios. These scenarios will be evaluated against a *baseline scenario* that assumes minimal electrification and no additional climate policies beyond those already enacted into law.

This study was commissioned by the McKnight Foundation in collaboration with GridLab and is an extension of two previous studies performed by Vibrant Clean Energy, LLC (VCE). The first previous study was commissioned by the Midcontinent Independent System Operator (MISO) to determine the effects of co-optimization for low-emission futures across the MISO footprint[1]. That study was primarily focused on assessing the impacts of high levels of renewables across MISO as emissions are reduced. The second previous study was commissioned by the University of Minnesota and VCE performed system modeling of MISO to determine how Minnesota might change with higher amounts of renewables and storage[2]. These two previous studies were developed around the electricity grid only, with minimal electrification of other sectors. They also only modeled the MISO footprint. The present study expands on those previous studies in several ways. First, the WIS:dom (Weather-Informed Systems: design, operation, markets) optimization model was expanded and enhanced. Secondly, the study is over the economy rather than just electricity. Thirdly, the demand-side is studied in much greater detail. Fourthly, the WIS:dom optimization model solved for the entire US Eastern Interconnection footprint.

The study has shown that the economy in Minnesota can decarbonize by 80% (from 2005 levels) by 2050. All the decarbonization pathways involve deeper energy efficiency of existing electric demands (particularly in the industrial sector), heavy electrification of transportation, transitioning heating of space and water from natural gas and resistive heating to heat pumps, building new zero-emission generation technologies, and retiring fossil-fuel generation.

The electrification of other sectors provides the electricity sector with new demands, which have different load profiles to existing demands and have greater flexibility potential. These new loads provide increasing sales for the electricity sector to invest against. Further, the greater flexibility allows the electricity grid to incorporate more variable resources, which are low-cost and near-zero emissions. Further, the electrification provides net cost savings for consumers because the reduction in spending on other energy supplies (natural gas for heating and gasoline for transportation) outweighs the additional spending in the electricity sector for the electrified loads.

It was also demonstrated by the study that electrification and decarbonization at the same time can reduce the exposure to escalations of fuel prices (e.g. natural gas). These potential price increases would be unavoidable in a fossil-heavy future, while a future that is electrified and decarbonized can avoid such sensitivity. The study showed that if natural gas costs were higher, Minnesota could find itself spending a cumulative additional $16 billion on electricity by 2050. This compares with an estimated reduction in spending on energy in Minnesota of between $16 to

[1] https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=223249
[2] http://energytransition.umn.edu/wp-content/uploads/2017/07/Workshop-Report-Final.pdf

$51 billion by 2050 if the economy electrifies and decarbonizes. This translates to a saving of between $600 to $1,200 per Minnesotan household per year.

The electrification and decarbonization of the Minnesotan economy could create more new jobs in the electricity sector than without these efforts. The study showed that on average decarbonized scenarios provided approximately 20,000 more full-time jobs than the baseline scenario (an additional 50%). These job increases are dependent on new generation assets being built to provide electricity for the growing new demand driven by the electrification of other sectors.

All the scenarios performed in the study showed declining cost per delivered unit of electricity for Minnesota through 2050. Part of the decline is due to growing demand and another portion is due to transitioning to generation assets with lower operating costs. These cost reductions, compared with average 2017 costs[3], could be less if more investment is required in the distribution grid or other spends were necessary within the system. The recent trend in electricity costs has been lower generation costs in exchange for higher costs in delivery of the electricity (e.g. transmission and distribution upgrades, interconnections costs, and reserves). The WIS:dom optimization model does not capture all the delivery costs explicitly (such as distribution costs), but does capture explicitly transmission costs, generation costs, demand-side management (DSM) / demand response (DR) costs, and implicitly distribution costs. The modeling showed continued downward pressure on the cost of generation, with overturn of older/uneconomic existing generation to new near-zero operating cost clean technologies. It further showed that the increased spending on transmission and sub-transmission (along with implicit distribution costs) was strongly outweighed by the decreased generation costs.

The modeling performed was designed to have a pathways component. This enabled comparisons between scenarios at different times. Overall, the total emissions for all the scenario pathways appear relatively similar until approximately 2030. The transition to natural gas from coal, from an emissions perspective, can look similar to a lower-emission driven target. However, once along a pathway that invests heavily for natural gas, emission reductions cease and even climb in the longer term. This occurs because along those pathways with natural gas infrastructure there are sunk costs that must be recuperated; which slows investment in new lower cost generation. Essentially, decisions made earlier in the infrastructure buildout may lead to similar results in the short term, but has the potential to limit future emission reductions many years in the future.

One scenario was dedicated to the whole Eastern Interconnection electrifying and decarbonizing along with Minnesota. If Minnesota were to decarbonize its economy by 80% by 2050, the impact on emissions from the whole Eastern Interconnection would be small (not considering the leadership role that Minnesota would impart on the other states in the Eastern Interconnection). When the whole Eastern Interconnection decarbonizes with Minnesota there was a different pathway. Changes in the rest of the Eastern Interconnect creates feedback with decisions in Minnesota, which results in altering deployment of technologies to strengthen the progress across the whole Eastern Interconnection. A counter-intuitive result was that transmission needs decreased with electrification and decarbonization for the whole Eastern Interconnection. This was driven by changing local resource correlation to demand profiles and the higher flexibility available across the Eastern Interconnection to use variable resources efficiently.

Finally, the scenarios were dispatched at 5-minute intervals with 3-km weather data for an entire year for each investment period across the entire Eastern Interconnection. The highly detailed dispatch allowed the modeling to determine the benefits and disadvantages of each resource (generation, demand, storage, and transmission) and formulate an efficient way to reliably

[3] Average retail cost of electricity in Minnesota for 2017 was 9.9¢/kWh.

provide power. In fact, for all scenarios performed, the WIS:dom model was successful at providing the necessary balance between supply and demand for every 5-minutes throughout the footprint, without fail.

II. Scenarios Performed

The McKnight Foundation, GridLab, VCE, and participant stakeholders identified a total of eight main scenarios to deploy the WIS:dom optimization model on for this study. Within some of the scenarios there was up to two branches that altered a single parameter to investigate the impact of that single change. Therefore, in total there was thirteen scenarios created and analyzed.

Every scenario was conducted over the entire US portion of the Eastern Interconnection for generator siting, transmission expansion, storage capacity expansion, demand-side resource deployment, transmission power flow, economic dispatch, and metric tracking. The time horizon for all the scenarios was 2050. The WIS:dom optimization model output for the investment periods 2017, 2020, 2025, 2030, 2040 and 2050. For each investment period, economic dispatch, power flow, and load balancing was performed for a single year with 5-minute intervals and 3-km weather data.

The scenarios performed for the study are listed below. The list includes the major features of each scenario that are assumed within the WIS:dom optimization model. The detailed results section will refer back to this list to identify the scenarios discussed.

A. ***Baseline:*** Current enacted policies and regulations. No carbon goals. WIS:dom makes economic choices to build new generation or retire old generation. All nuclear power plants in Minnesota stay online through their current licenses, which are 2030 (Monticello) and 2033/34 (Prairie Island). Load growth projections assumed to not include electrification of other sectors, and flexibility remains low. Cost projections are provided by the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) 2017 dataset[4]. Locational multipliers for capital and fuel costs are provided by VCE. The initialization (seeding) of the WIS:dom optimization model is based upon data for the end of 2016. VCE combined publicly available datasets for generation[5] and internally produced (reduced form) datasets for transmission. The baseline scenario has two branches;
   1. ***Allowing interstate transmission expansion (Baseline w/ Tx)***; WIS:dom can build new transmission based on co-optimization to allow sharing of resources across state boundaries more efficiently; market friction elevates transmission costs between RTO boundaries.
   2. ***Blocking interstate transmission expansion (Baseline w/o Tx)***; WIS:dom cannot build new transmission between states beyond estimated 2017 capacities; transmission for the integration of renewables within states to load centers/substations is applicable.

B. ***MN deep decarbonization:*** A carbon emission reduction target for Minnesota is set such that by 2050 the entire economy can only emit 20% of the carbon dioxide compared with 2005 emission levels[6]. As discussed in Section III, to achieve the 80% economy-wide reductions, the electricity sector must decarbonize by 91%. Substantial electrification and energy efficiency are assumed and are explained in detail in Section III. The electrification enables flexibility in the demand resources. The rest of the Eastern Interconnection and model assumptions are as in ***Baseline***.
   1. ***Allowing interstate transmission expansion (Decarb w/ Tx)***; see **Baseline** description around transmission modeling.
   2. ***Blocking interstate transmission expansion (Decarb w/o Tx)***; see **Baseline** description around transmission modeling.

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[4] https://atb.nrel.gov/electricity/2017/index.html
[5] https://www.eia.gov/electricity/data/detail-data.html
[6] The total carbon dioxide emissions allowed by 2050 for Minnesota is 22.4 million metric tons (20% of 111.9 million metric tons in 2005). Electrification of other economic sectors results in the rest of the economy emitting 17.9 metric tons by 2050 (the residual emissions from the extremely hard to decarbonize sectors). Thus, the electric sector in Minnesota must provide electricity while emitting at most 4.5 million metric tons by 2050 to achieve the 80% target. Import/export emissions are included in the computations of emissions.

C. ***High natural gas (NG) costs:*** Use the AEO[7] high natural gas price forecast to determine the impacts on the baseline and decarbonization scenarios. The rest of the Eastern Interconnection are as in **Baseline**.
   1. ***Baseline with high natural gas costs (Baseline + High Gas)***; Apply high natural gas prices to the ***Baseline w/ Tx*** scenario.
   2. ***Decarbonization with high natural gas costs (Decarb + High Gas)***; Apply high natural gas prices to the ***Decarb w/ Tx*** scenario.

D. ***Zero emission decarbonization MN:*** Minnesota electricity must be completely decarbonized by 2050 (including imported power). All other assumptions identical to the ***MN deep decarbonization*** scenario.
   1. ***Allowing interstate transmission expansion (100% w/ Tx)***; see **Baseline** description around transmission modeling.
   2. ***Blocking interstate transmission expansion (100% w/o Tx)***; see **Baseline** description around transmission modeling.

E. ***Eastern Interconnection decarbonization with MN:*** The entire Eastern Interconnection electrifies and decarbonizes the economy to 80% (of 2005 emissions) by 2050. All other assumptions identical to the ***MN deep decarbonization*** scenario.
   1. ***Allowing interstate transmission expansion (EI w/ Tx)***; see **Baseline** description around transmission modeling.

F. ***MN deep decarbonization with dominant distributed energy resources (DERs):*** Minnesota decarbonizes while giving preference to localized resources such as electric vehicles (EVs), DSM, DERs, and additional energy efficiency (EE). All other assumptions identical to the ***MN deep decarbonization*** scenario.
   1. ***Allowing interstate transmission expansion (Local Decarb)***; see **Baseline** description around transmission modeling.

G. ***MN deep decarbonization with less flexibility:*** Minnesota decarbonizes through electrification, but the electrification does not provide as much flexibility potential. All other assumptions identical to the ***MN deep decarbonization*** scenario.
   1. ***Allowing interstate transmission expansion (Low-Flex Decarb)***; see **Baseline** description around transmission modeling.

H. ***MN deep decarbonization nuclear sensitivity:*** Minnesota decarbonizes, but the treatment of nuclear power plants is changed for two different sensitivities. All other assumptions identical to the ***MN deep decarbonization*** scenario.
   1. ***Nuclear power plants can retire when economic (Nuclear Retirements)***; Allow the nuclear power plant to retire based on economics for the ***Decarb w/ Tx*** scenario.
   2. ***Nuclear power plants must relicense through 2050 (Nuclear Relicenses)***; Enforce nuclear power plant relicenses through 2050 for the ***Decarb w/ Tx*** scenario.

ID		Scenario Name	Transmission Expansion	Emission Target	Electrification	MN Flexibility Level	EI Flexibility Level	NG Cost	Nuclear Retirement	DERs
A	1	***Baseline***	Interstate & Intrastate Allowed	Current Policies	EI Minimal	0% to 2.1% by 2050	0% to 2.1% by 2050	NREL ATB - Low	Follow License Schedule	No Lower Limit
	2		Intrastate Allowed Only							
B	1	***MN Deep Decarbonization***	Interstate & Intrastate Allowed	**MN 80% Economy Reduction**	**MN Extensive**	**0% to 20.8% by 2050**	0% to 2.1% by 2050	NREL ATB - Low	Follow License Schedule	No Lower Limit
	2		Intrastate Allowed Only							
C	1	***High NG Cost***	Interstate & Intrastate Allowed	Current Policies	EI Minimal	0% to 2.1% by 2050	0% to 2.1% by 2050	**AEO 2018 - High**	Follow License Schedule	No Lower Limit
	2			**MN 80% Economy Reduction**	**MN Extensive**	**0% to 20.8% by 2050**				
D	1	***Zero Emission Electricity MN***	Interstate & Intrastate Allowed	**MN 84% Economy Reduction**	**MN Extensive**	**0% to 20.8% by 2050**	0% to 2.1% by 2050	NREL ATB - Low	Follow License Schedule	No Lower Limit
	2		Intrastate Allowed Only							
E	1	***EI Decarbonizes with MN***	Interstate & Intrastate Allowed	**EI 80% Economy Reduction**	**EI Extensive**	**0% to 20.8% by 2050**	**0% to 20.8% by 2050**	NREL ATB - Low	Follow License Schedule	No Lower Limit
F	1	***MN Deep Decarb. with Dominant DERs***	Interstate & Intrastate Allowed	**MN 80% Economy Reduction**	**MN Extensive**	**0% to 32.3% by 2050**	0% to 2.1% by 2050	NREL ATB - Low	Follow License Schedule	**50% from DERs**
G	1	***MN Deep Decarb.with less Flexibility***	Interstate & Intrastate Allowed	**MN 80% Economy Reduction**	**MN Extensive**	**0% to 5.2% by 2050**	0% to 2.1% by 2050	NREL ATB - Low	Follow License Schedule	No Lower Limit
H	1	***MN Deep Decarb. Nuclear Sensitivity***	Interstate & Intrastate Allowed	**MN 80% Economy Reduction**	**MN Extensive**	**0% to 20.8% by 2050**	0% to 2.1% by 2050	NREL ATB - Low	**Allow Early Retirement**	No Lower Limit
	2								**Keep Online Through 2050**	
			External Decision On Transmission Expansion	*Reductions is taken from the 2005 emission record*	*Electrification of Sectors*	*Percentage of Demand*		*2017 Release*		*Percentage of Demand*

Summary of the thirteen (13) scenarios performed for the present study. The table highlights the major components and assumptions that differentiates each scenario. The purpose of the scenarios was to explore possible futures that might occur for Minnesota as it attempts to decarbonize its economy. These scenarios provided the necessary insight to comment on the major hurdles that different futures might impose on the pathway possibilities.

[7] United States Energy Information Administration (EIA) Annual Energy Outlook (AEO) that provides forecasts for energy metrics.

III. Electrification Potential & Assumptions

For any study carried out there are input assumptions that influence the overall conclusions. For this study, the most significant assumptions are how much energy is transferred from other sectors to electricity due to electrification, the geographic and temporal profiles of the electrified loads and the flexibility of these new energy (electricity) demands. The WIS:dom optimization model primarily considers electrical (and some thermal) energy. Therefore, input demands are required for the model to optimize upon. A detailed description of the WIS:dom optimization model, its internal assumptions, logical equations, and input data is provided in Section V of this report. The present section is dedicated to assumptions specific for this study related to the electrification component.

For the purposes of this study the energy demand is disaggregated into four categories: Residential, Commercial, Industrial, and Transportation. The main changes that occur during electrification are as follows:

I. Transportation electrification,
II. Space heating in the residential sector transitioned to heat pumps,
III. Space heating in the commercial sector transitioned to heat pumps,
IV. Water heating in the residential sector transitioned to heat pump water heaters,
V. Water heating in the commercial sector transitioned to heat pump water heaters,
VI. Energy efficiency programs applied to residential, commercial, and industrial sectors.

The combination of changes I-VI above enables sufficient electrification and reduction in emissions outside the electricity sector for Minnesota to meet its goal of 80x50 (80% reduction in emissions by 2050). The annual energy needs for Minnesota were provided by Synapse Energy Economics (Synapse) along with the remaining emissions outside of the electricity sector. These energy and emission numbers provided boundary conditions for the WIS:dom optimization model to solve for.

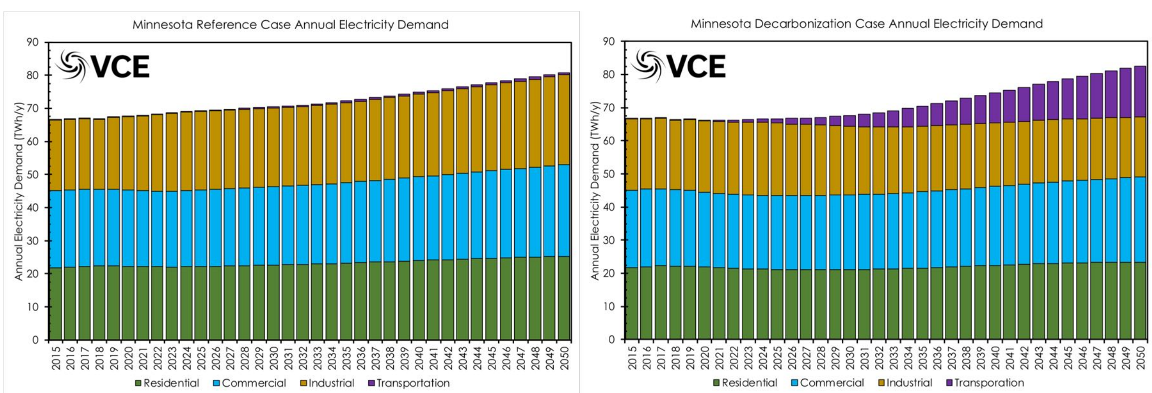


Figure 1: Synpase provided electricity demand for each sector for the Baseline case (left) and the Decarbonization case (right). The electricity sector must undergo dramatic change between 2015 and 2050. There is strong energy efficiency, and new loads appearing in the demand.

Due to the new demands being added to the electricity profile and the reduction in traditional demands through energy efficiency, the total amount of electricity required by 2050 is only slightly higher for Decarbonization than for the Baseline. Figure 1 displays the total annual electrical energy demand for each year between 2015 and 2050 for the two cases. The figure illustrates the changing composition of the demand, but masks many of the changes within each sector. The increase in electricity demand by 2050 for the decarbonization case over the baseline case is 1,690 GWh (2.1%).

As there is such a small increase in the overall electrical energy required to achieve deep electrification and decarbonization, more explanation is required to the composition of the sectors. The largest assumption is the use of energy efficiency. There are deep reductions in traditional demands projected using these programs. Figure 2 displays the cumulative impact of energy efficiency assumed in the demand data. The figure shows that it is assumed that end-use electricity demand is reduced by 19,600 GWh by 2050 through the energy efficiency programs. The reductions are reported against the Baseline case.

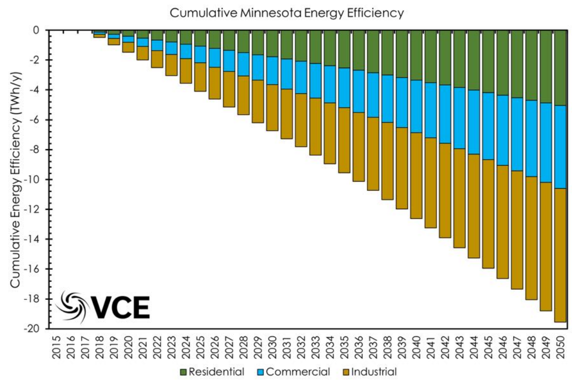


Figure 2: The cumulative adjustment to Minnesota traditional electricity demands from energy efficiency. The programs combine to reduce the end-use electricity demand by 19,600 GWh by 2050. These energy efficiency savings are reductions compared to the Baseline case.

With energy efficiency there is a reduction in the demand; however, Figure 1 shows an overall increase in demand for the decarbonization case. The increase comes from three areas. The first is the electrification of space heating. There are two components to this electrification; a decrease in demand by transitioning electric resistive heating to heat pumps and an increase in demand by transitioning natural gas furnaces to heat pumps. These changes are assumed to occur in the residential and commercial sectors. The second area of increased demand is transitioning water heating to heat pump water heaters. Similar to the space heating, some of the transition involves moving from electric resistive water heaters to heat pump water heaters and some comes from natural gas water heaters to heat pump water heaters. Figure 3 shows the cumulative fraction of space and water heating that become heat pumps by year. The figure estimates growth in the adoption of heat pumps more rapidly for residential than commercial sectors; with 2050 fractions approaching 60 to 75% of all space and water heated by heat pumps across Minnesota.

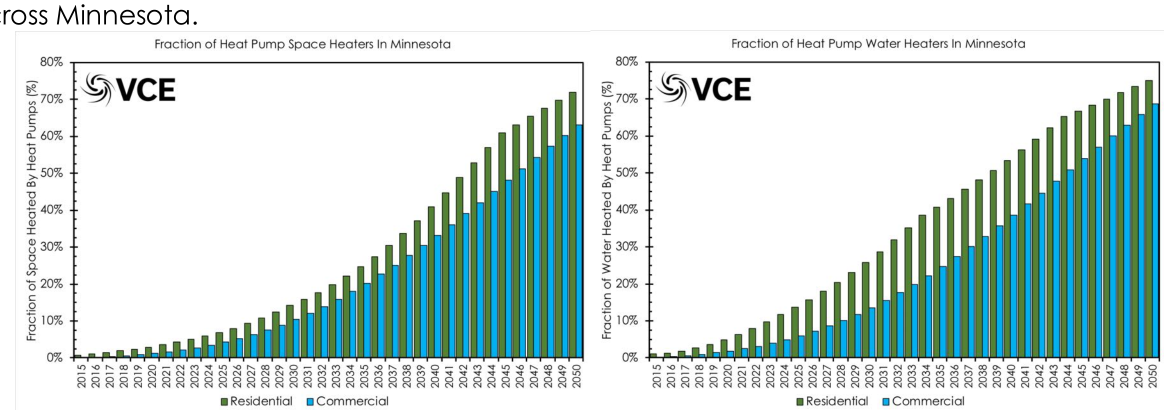


Figure 3: The cumulative fraction of space (left) and water (right) heating provided by heat pumps by year. There are separate fractions for residential and commercial sectors. It is assumed that the adoption in the residential sector is faster than in the commercial sector. By 2050, 72% of residential and 63% of commercial spaces in Minnesota are heated by heat pumps. For water heating, the numbers are slightly higher, 75% and 69% of water heating occurs by heat pumps in the residential and commercial sectors, respectively.

The third, and most substantial, increase in demand comes from electrification of transportation. It is assumed that light-, medium-, and heavy-duty transportation to some degree can be electrified. The most readily available sub-sector to electrify is light-duty vehicles, while medium- and heavy-duty are assumed to take a slower adoption curve. It is assumed that 89% of all light-duty vehicle miles travel are electrified by 2050, which is displayed in Figure 4. Overall, the electrification of transportation covers 22% of all ton-miles by 2050. The electrification of transportation is one of the biggest areas of emission reduction for Minnesota, if the electricity sector can be decarbonized alongside the electrification.

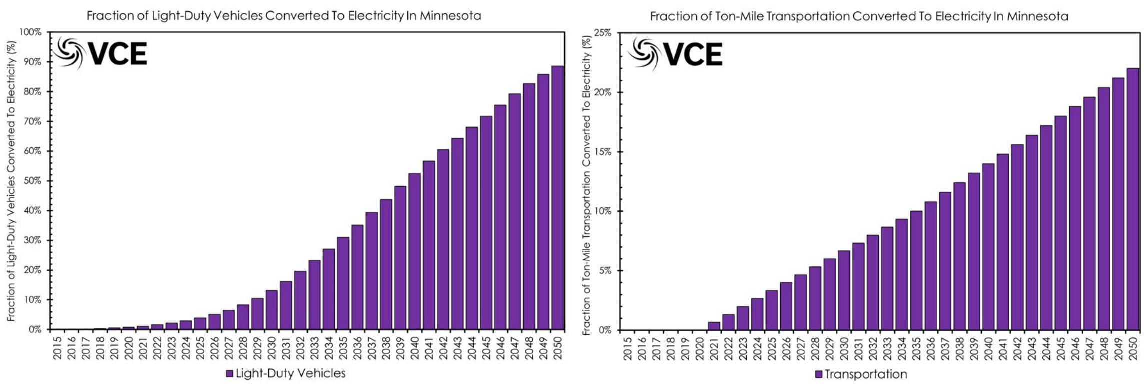


Figure 4: The cumulative adoption curves for light-duty vehicles (left, in fraction of vehicle miles traveled) and all transportation (right, in fraction of ton-miles). The assumption is low adoption to 2020, rapid growth through 2030 and approximately linear growth from 2030 to 2050. The growth in electrification of transportation increase demand substantially in Minnesota.

The additional demands from space and water heating along with transportation are somewhat compensated for with the additional energy efficiency assumed in each sector. Below, in Figure 5, it is shown how transportation is the largest net growth in demand, while the other three sectors have net reductions in demand. Both residential and commercial fall by smaller amounts compared with industry because of the added demands from electrified heating (space and water). Once the energy demand changes are summed, the resulting electrical energy needs for decarbonization by 2050 is approximately the same as in the baseline case.

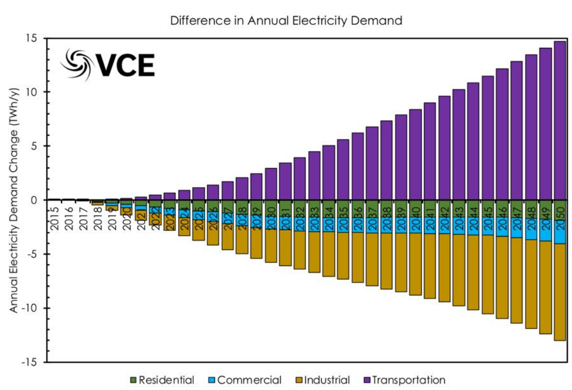


Figure 5: Net electrical energy requirements by sector. Transportation creates strong demand increases, while industry (through energy efficiency) creates strong demand decreases. The electrification of space and water heating does not outpace assumed energy efficiency for residential and commercial sectors; however, it does limit the decrease in demand substantially.

The purpose of electrification of other sectors is to remove greenhouse gas (GHG) emissions from sources outside the electric sector and then have the electric sector decarbonize, since the types of clean energy for the electricity sector are low-cost. Figure 6 displays the baseline and decarbonization GHG emissions for those sectors outside of electricity. The reduction in GHG emissions by electrification is 44 million metric tons by 2050. That represents 71% of all GHG emissions coming from sources outside the electricity sector in 2017. It also accounts from more emissions than the entire Minnesota electricity sector emitted in 2017. This illustrates one of the most important features of electrification. Decarbonizing the electricity sector alone will not reduce GHG emissions enough to reach the 80% reduction by 2050.

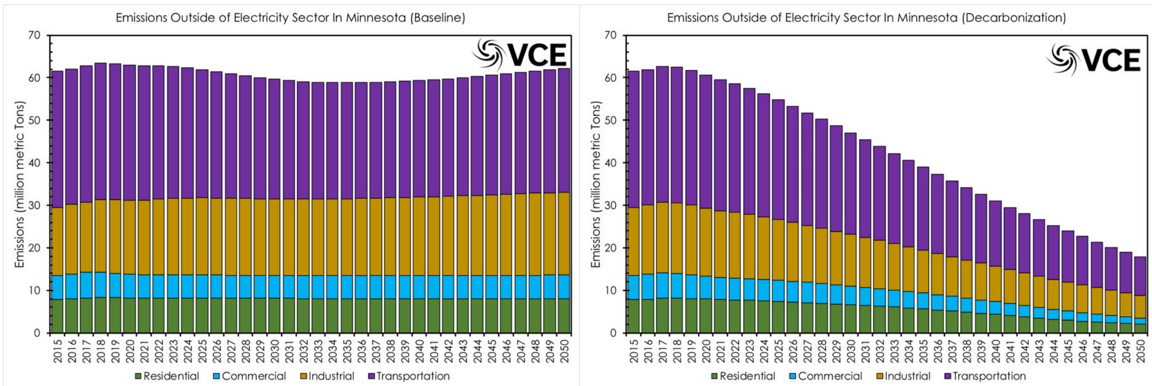


Figure 6: The GHG emissions from sources outside the electricity sector under the baseline case (left) and the decarbonization case (right). The GHG emissions from all four sectors are decrease substantially by 2050 in the decarbonization case compared to the baseline case. The largest decreases occur within the transportation and industrial sectors. By electrifying energy needs, the GHG emissions from sources outside the electricity sector falls by 44 million metric tons (71%). That reduction is more than the entire electricity sector emitted in 2017.

The GHG emissions still present by 2050 from sources outside electricity total 17.9 million metric tons. Therefore, to meet the 80% reduction (from 2005 levels) in GHG emissions from the Minnesota economy by 2050, the electricity sector can only emit a maximum of 4.5 million metric tons. This emission number was calculated by taking the 2005 emission level, 111.9 million metric tons, and reducing it by 80%, leaving a total of 22.4 million metric tons. The emission reduction for the electricity sector is equivalent to 91% decarbonization (while providing more electricity) from 2005 levels.

The components of electrification are important. Even though Figure 1 displays relatively little change in end use annual electricity needs, it does show that the composition of the demand has changed significantly. The different electrified demands have new profiles that are not represented in the electricity profiles that exist today. To compute the new additional demand profiles at hourly (and 5-minutely) resolution VCE built algorithms that used weather data, human social patterns, and the properties of the new technologies. These profiles then formed the basis for the demand-side flexibility as well as the input load profiles for the WIS:dom optimization model.

For electric vehicles, first the historical total amount of gasoline purchased per month and vehicle miles traveled were compiled[8,9]. These numbers provided the necessary analogue for the driving patterns for each month, as well as the additional energy use for heating and cooling the vehicles in each season. Driving patterns and energy use were also correlated to the weather throughout those months. Secondly, the temperature impacts on the electric batteries was considered. It is well known that batteries are strongly influenced by temperature. Outside of their normal operating temperature (~20°C / 68°F) the efficiency of the battery is reduced[10]. Colder temperatures have a greater impact than higher temperatures. Colder temperatures can increase energy consumption per unit distance traveled by up to 30%. Battery thermal management (BTM) devices can reduce this impact. However, overall a combination of the

[8] Gasoline Sales: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=a103600001&f=m
[9] Vehicle Miles Traveled: https://www.fhwa.dot.gov/policyinformation/travel_monitoring/historicvmt.cfm
[10] https://www.sciencedirect.com/science/article/pii/S0378775316308941

additional heating required for the cabin in winter months along with reduced efficiency of the battery pack increases the electricity energy requirements by 40% compared with summer months, even when including the fact that people tend to travel more miles in summer months. Combining these factors with charging pattern behaviors, it is determined that peak charging would occur in the winter months overnight[11]. These charging patterns are inputs to the WIS:dom optimization model. These patterns can be altered by the model if it is cost effective to do so (paying customers to not charge, and do so at a later date). Figure 7 shows the average input profiles for daily electricity needs and the diurnal cycling of charging.

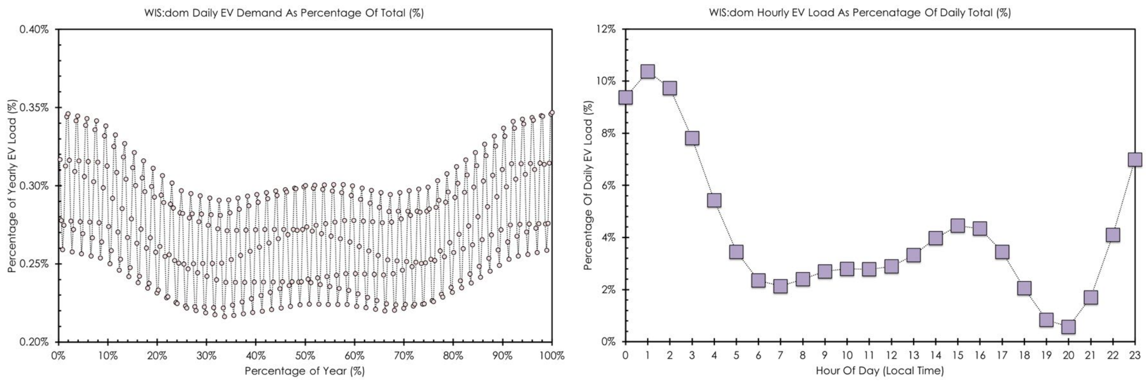


Figure 7: The daily electricity requirements as a percentage of annual transportation energy that is electrified (left) along with the diurnal profile based upon social patterns (right). The electricity needs are higher in winter than summer, and the charging profile is higher overnight than during the day. These inputs can be adjusted by the WIS:dom model (for a cost) to shift the charging around supply, if it is economical to do so.

For heating there are two main components, space and water. Space heating is very strongly correlated with the ambient air temperature. Water heating is also correlated to ambient air temperature, but to a much smaller extent (most customers want hot water available all day, every day). The temperature from the weather data was used to compute the temperature-heating demand correlation profiles. The amount of end-use energy was computed for each month based upon natural gas sales[12]. With the correlation calculated the electrical energy required for each day was computed. From the diurnal cycle of temperature, it was possible to compute when the electricity was required throughout the day. Commercial and residential space and water heating combine to produce Figure 8. The electrical energy requirements for heating in winter is 6- to 7-fold greater than in summer. There is still some electricity required for heating in the summer months for water heating and build stock that is kept at a relatively constant temperature, regardless of season. There is a clear weekly cycle for the heating, due to the coincident electrical needs of the residential and commercial heating. The diurnal cycle is an average requirement that is dependent on the diurnal temperature changes that occur in Minnesota. As with the EVs the highest demands occur in the winter months in the evening and night-time hours.

[11] https://www.energy.gov/sites/prod/files/2014/12/f19/SGIG-EvaluatingEVcharging-Dec2014.pdf
[12] https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_m.htm

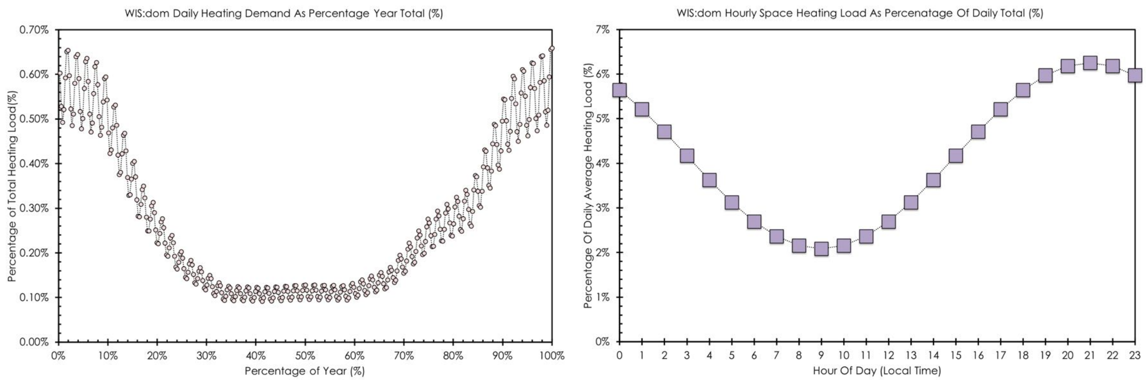


Figure 8: The daily requirements of electricity for heating (left) and the diurnal cycle for heating (right). The panels show the aggregated requirements for space and water heating for both residential and commercial buildings. There is still heating needs in summer for water heating and for some building stock that is kept at a constant temperature. The electrical energy needs in winter is 6- to 7-fold greater than that in summer for Minnesota. The weekly cycles are more apparent in winter compared with summer due to the commercial and residential coincident requirements.

The new demands for electricity are additions to the traditional load profiles. The traditional loads are exposed to energy efficiency, which reduces the total amount of electricity required. It was assumed that energy efficiency applies as a percentage reduction for every 5-minute demand interval. Therefore, the more electricity required in that time interval, the larger the energy efficiency reduction. The culmination of all these demand changes is a very different time series of the load for each investment period as more loads are electrified.

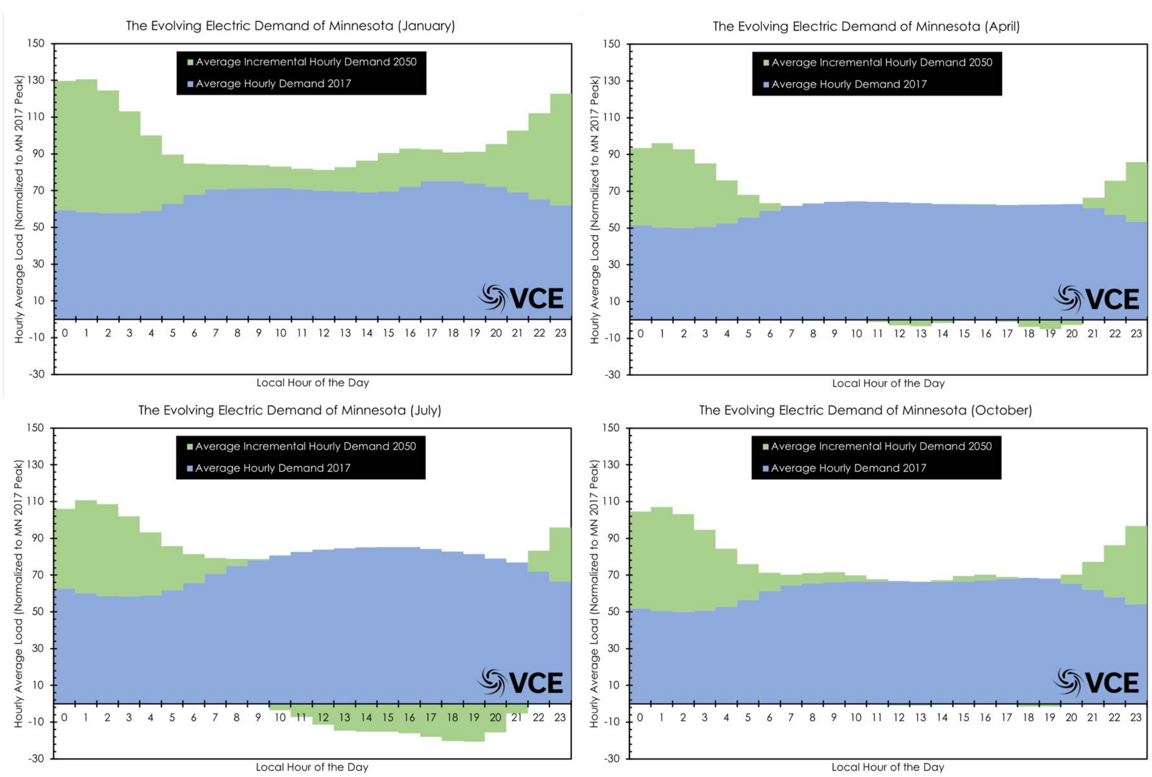


Figure 9: The average hourly demand profiles for four months: January (top-left), April (top-right), July (bottom-left), and October (bottom-right). Blue shows the 2017 normalized load (100 = 2017 peak hourly demand) and green shows the incremental demand by 2050. In colder months there is a substantial increase in electricity demand, while in the hotter months the increase is smaller, or even negative in day-time hours.

Figure 9 shows the average hourly daily cycle for four months (January, April, July, and October) to represent each season. The WIS:dom optimization model executes over each 5-minute interval for a year, but for display purposes that is cumbersome. This Figure illustrates the general changes in demand profiles between 2017 and 2050. The changes in demand result in a reduction in day-time electricity requirements in warmer months, but an increase (substantial) in electricity needs for the night-time hours in the colder months. Figure 9 shows average hourly profiles over four months. Figure 10 shows the average hourly electricity requirements for 2017 and 2050, normalized to the peak of 2017 (=100). The figure shows that Minnesota transitions from a summer to a winter peaking state. This is due to energy efficiency of traditional loads in combination with new loads in heating and EVs, which are highest in colder conditions.

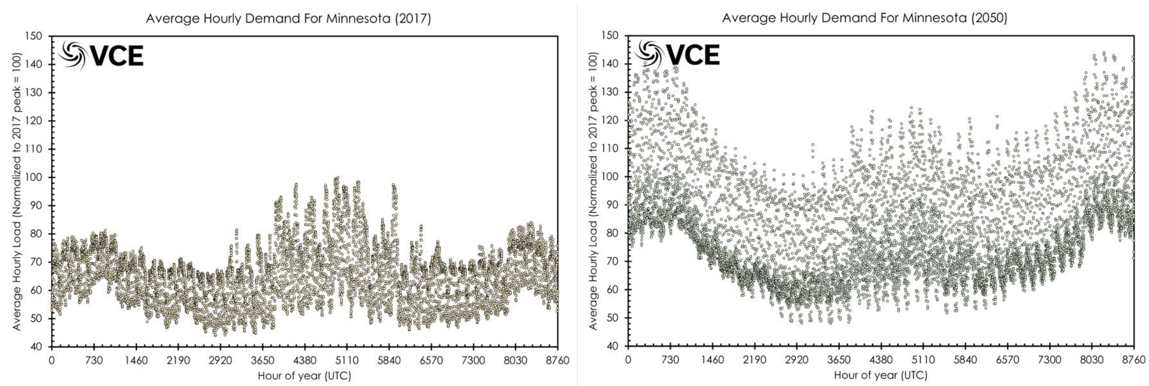


Figure 10: The average hourly demand profile for Minnesota for 2017 (left) and an electrified and decarbonized 2050 (right). The values are normalized to the peak demand in 2017 (=100). The panels show that the demand has become more oscillatory diurnally. Additionally, it can be seen that Minnesota has become a winter peaking state. The growth in electricity needs is highest in the colder months.

In Figure 11, the ratio of the hourly demand between 2050 and 2017 is shown. It demonstrates the higher increase in demand for the winter months compared with the summer months. This property is important for flexibility. It is assumed that these new loads are more capable of flexibility and for the colder time periods there is a higher percentage of these demands comprising the total demand. Therefore, there is more available flexibility for those time periods.

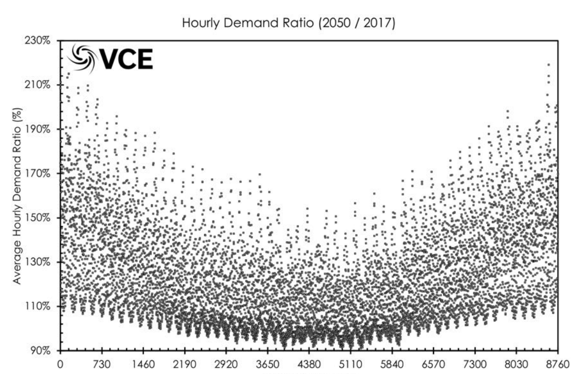


Figure 11: The ratio of the 2050 hourly loads to the 2017 ones. The plot illustrates the impact of these new demands (including EE). Essentially, the summer month minimums in 2050 are lower than in 2017 and the maximums in winter are up to twice those in 2017.

The input demand profiles are for each of the investment periods and the profiles change depending on the amount of each sector electrified (and the energy efficiency applied). In addition, the fraction of each 5-minute interval for each demand type is stored for WIS:dom to determine the amount of demand-side flexibility that is available. These demand-side resources are dispatched by WIS:dom if it determines the cost of doing so is lower than additional supply resources. The demand-side resources must balance with user-defined reductions allowed (for Demand Response) or be a net-zero for demand-side management (DSM). Essentially, WIS:dom is informed of the demand-side in the absence of cost signals or changing social behaviors. WIS:dom can then alter those demand resources based on price signals to shift the use of electricity. These resources are separate to storage, which in an abstract sense performs the same function.

In the decarbonization cases, it is assumed that 50% of the EV fleet can be has a flexible charging schedule. No vehicle-to-grid is allowed. If there is demand present, WIS:dom must pay a charge to shift the demand to another time period. The demand for EVs must be balanced within a five-day time period. It is further assumed that 25% of heating demands can be used for flexibility, which must be in balance within a four hour-time period. Again, WIS:dom must pay a charge per MWh shifted to dispatch the DSM resources. A minimum charge of $21 / MWh is charged to dispatch DSM resources, with that charge escalating to $60 / MWh up to the limit of the flexibility. The blocks of DSM are in 5-minute intervals. Thus, they can contribute to resource adequacy within WIS:dom. The model could decide to not use the DSM resources, in which case the input demand profile must be met by supply-side resources.

The present section has explained a new formulation for demand-side shifts that could occur due to electrification. These assumptions and computations result in a future demand resource mix very different to the one that exists today. For Minnesota, that means an evolution that moves the peak demand from summer day-time to winter night-time. Further, it provides the Minnesota grid with various new sources of flexibility that could be low-cost. Indeed, there is more flexibility available at (the new) peak times than at other times.

The general assumption around DSM is predicated on the demand-side participating in the market; providing and receiving signals that can utilize the flexibility that could arrive from electrification. The increased electricity needs along with its new flexibility provides more room for variable resources to operate and a combination of these resources to provide robust power supply. Finally, the demand-side changes involve many more modular components (individual EVs, heat pumps, water heaters, etc.) and as such enable finer adjustments along with the statistical knowledge of fewer large impact events of units disappearing (e.g. a large coal-fired power plant tripping offline). Therefore, the demand-side becomes an integral area for the planning of the system and, as will be discussed in later sections, can be utilized to accommodate more low-cost, low-emission variable resources.

In WIS:dom, for the present study, rooftop solar PV is considered a generation resource. As such, it is determined via siting within the core of WIS:dom codes. A reduction of demand within the region for thermal heat gain on the rooves is calculated; and a computation is made for the carrying capacity of the existing distribution grid. Implicitly, additional spend is allocated if the rooftop solar is installed above that carrying capacity. Essentially, rooftop PV does not "mask load" and does participates in the markets. Rooftop solar PV does not have a transmission cost associated with it, and the losses are assumed to be the average of the distribution grid (unless power flows out to the transmission grid).

No costs associated with the build out of infrastructure of the electrification is considered by WIS:dom. It is assumed that those costs are a burden on other sectors and not the electricity sector. All costs for new electricity capacity and fuel come from the NREL ATB 2017 dataset[13]. Two

[13] https://atb.nrel.gov/electricity/2017/index.html

exceptions exist, AEO 2017 high gas price[14] for one sensitivity and storage costs are taken from a previous study performed by VCE[15].

[14] https://www.eia.gov/outlooks/aeo/
[15] http://energytransition.umn.edu/wp-content/uploads/2017/07/Workshop-Report-Final.pdf

IV. Detailed Overall Findings

In this section, the major metrics from all the scenarios are compared, discussed and analyzed for general conclusions. All the outputs from the WIS:dom optimization model and spreadsheets for each scenario (that are used to produce the present section) are provided for use by McKnight Foundation and GridLab to use as required. In the next section, each scenario will be discussed in more detail with respects to the WIS:dom outputs and scenario specifics.

The first major metric is the cost per unit of electricity provided to customers. The WIS:dom optimization model explicitly computes the fixed and operating costs for each generator to provide service. It also calculates the cost of transmission, wheeling charges, and ramping costs for generators. In addition, WIS:dom considers the cost to the system to provide demand-side resources. Finally, the model (implicitly) provides the cost of distribution upgrades by increasing the cost of electricity generation, transmission, storage and DSM by $22.43 / MWh[16]. This allocated $59.2 billion for distribution spending in 2017 across the Eastern Interconnection[17]. The adjustment is based on the need for WIS:dom to increase the infrastructure within the distribution grid (which is not explicitly modeled) for rooftop solar PV, residential DSM programs and other investment needs.

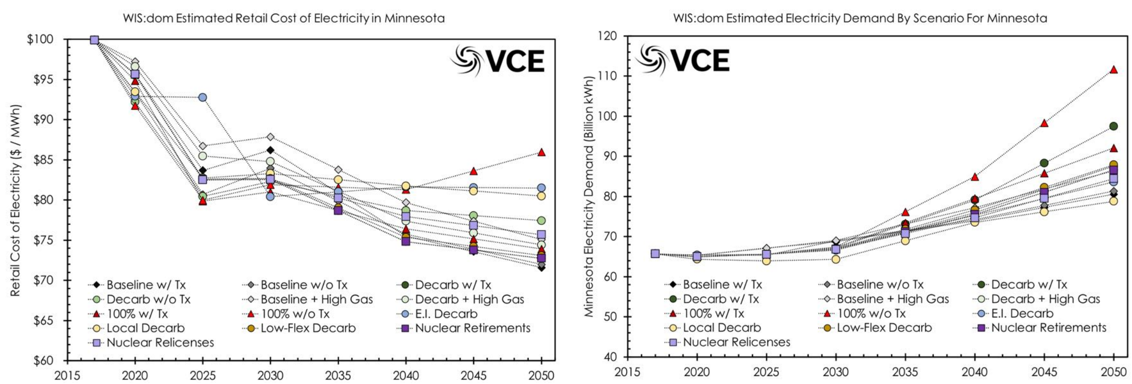


Figure 12: The estimated average cost per unit of electricity (left) and the total final electricity demand (right) by investment period. The cost per MWh on the left panel shows downward pressure, even with the static $22.43 / MWh for investment in the distribution system. The cost of electricity does include payment of sunk costs for retiring power plants that may not have cleared their capital debt. The right panel illustrates that electricity demand is rising through time. The differences are created by different amounts of storage and DSM that will increase the total electricity necessary for the system.

In Figure 12, the average cost per unit of electricity and total electricity demand is shown for all the scenarios over the investment periods. The cost of electricity per MWh reduces over time (even with the static $22.43 / MWh for distribution costs). The reduction in cost per unit of electricity is primarily driven by two factors: transitioning to low-cost variable resources that are sited efficiently to reduce the burden to the system (as well as retiring older less efficient plants with newer ones) and the increase in total electricity requirements for the system. The right panel of Figure 12 shows that the final electricity requirements are different for each scenario. The reason behind this is

[16] In 2017, the cost share for electricity can be broken down to approximately 59% for generation, 13% for transmission and 28% for distribution (https://www.eia.gov/energyexplained/index.php?page=electricity_factors_affecting_prices). It is assumed that the cost for distribution remains the same, in real terms, throughout the optimization. Therefore, to inflate the WIS:dom output costs to represent retail costs, the generation and transmission share (for 2017) is multiplied by 139%. This results in $22.43 / MWh additional spend for distribution costs. This is a generous addition, since the generation and transmission costs in WIS:dom include all the DSM costs, additional upgrade costs for increasing distribution carrying capacity, rooftop solar PV buildout, and market clearing prices. This approach is limited by a couple of factors. 1) The installation on rooftop solar, where capital investments are made by WIS:dom, but transmission may not be necessary. 2) The spend for distribution, in real terms, might need to increase with additional smart buildings and higher EV penetrations. Note, however, that the addition is per MWh, so the more electricity that is produced, the larger total amount spent on distribution.

[17] https://www.eia.gov/todayinenergy/detail.php?id=36675

varying amounts of storage and rooftop solar PV. More rooftop solar PV reduces the demand for cooling due to thermal heat gain calculations, while storage drives additional demand through its charge-discharge cycle. The impact of additional storage can be substantial for very high penetration levels. DSM can also alter the total amount of electricity required as this will alter the amount of storage required and its cycling. These numbers are consumed electricity and do not count transmission or distribution losses, which must be accounted for by the generation requirements.

The lowest-cost (per unit cost of electricity) scenarios are the baseline cases. This is to be expected because the baseline cases have the lowest amount of demand and there are no additional constraints on the system in terms of decarbonization (or electrification). The majority of the electrification and decarbonization scenarios are less than \$5 / MWh (0.5¢ / kWh) more expensive than the baseline scenarios. These scenarios achieve an 80% reduction in economy-wide emissions across Minnesota for a very small increase in the per-unit cost of electricity provided. Outlier scenarios, which are more expensive, include the local decarbonization scenario (another \$5 / MWh more expensive), the Eastern Interconnection decarbonization (another \$6/MWh above the other 80% decarbonization scenarios), and the 100% decarbonization scenario without transmission expansion (another \$10 / MWh more expensive). Therefore, the additional cost per unit of electricity to decarbonize Minnesota economy could be as low as 0.1¢ / kWh or as high as 1.2¢ / kWh, depending on the assumptions and constraints applicable to Minnesota. Later in this section of the report, it is shown that the cost of energy, as a whole, is reduced under the electrification and decarbonization scenarios, since there will be less spending in other sectors that have transitioned to electricity.

To get a better understanding of the changing costs for electricity, the total cost of electricity provided is needed, and is shown in Figure 13. The plot demonstrates that the total cost of electricity is reduced through 2025 then increases afterwards at different rates depending on the electrification, decarbonization, and other constraints imposed on the scenarios.

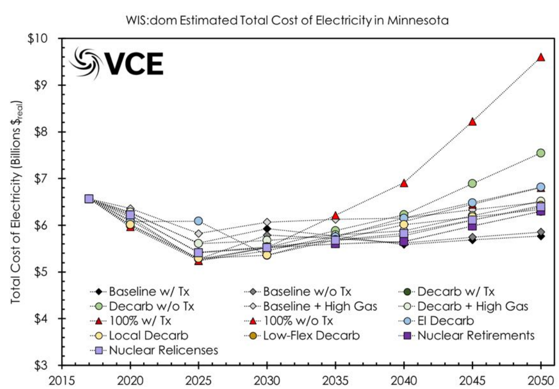


Figure 13: The estimated total cost of electricity by investment period for all scenarios. The total spending (in real dollars) declines for all scenarios from 2017 to 2025 and then increases beyond that timeframe out to 2050. The increase in spending is driven by higher demand, which outpaces the reduction in cost per unit of electricity. There are groupings of scenarios by 2050 that can be observed in the plot.

Figure 13 illustrates a number of different conclusions. First, that transmission expansion between Minnesota and other states (into MISO) can reduce the cost of decarbonization. In fact, it even reduces the cost without decarbonization. The annual saving by 2050 in the baseline scenario is \$86 million when interstate transmission expansion is allowed compared with not expanding the transmission capacity. For the decarbonization cases, this saving is dramatically increased. For the 80% economy-wide electrification and decarbonization, the annual savings by 2050 for Minnesota due to transmission expansion being allowed is \$1,249 million (\$1.25 billion), while the savings are even deeper if Minnesota completely decarbonizes the electricity grid (while electrifying) up to $2,797 million ($2.8 billion). These savings are compared with the same scenarios, but with transmission expansion between states being limited to 2017 levels. Secondly, the graph shows that the main scenarios for decarbonization are relatively tightly bunched in terms of total cost by 2050. This implies that Minnesota has numerous pathways to achieve the target of 80% by 2050 and even though the composition of each pathway may be very different, if planned properly the resulting costs and emissions can be very similar. Thirdly, spending in the electricity sector does not need to rise dramatically above 2017 spending to electrify and decarbonize; driven by the increasingly low-cost of variable renewables and the addition of new flexible demands.

A tantalizing prospect arises from Figure 13, if the total spending on electricity is not dramatically increased in many of the scenarios studied, then the cost to the customers for all energy must be reduced. This is because, in the decarbonization scenarios electrification is taking place, thus spending for those electrified sectors must be curtailed. In Figure 14, the total cumulative savings are displayed alongside the average annual saving per household in Minnesota.

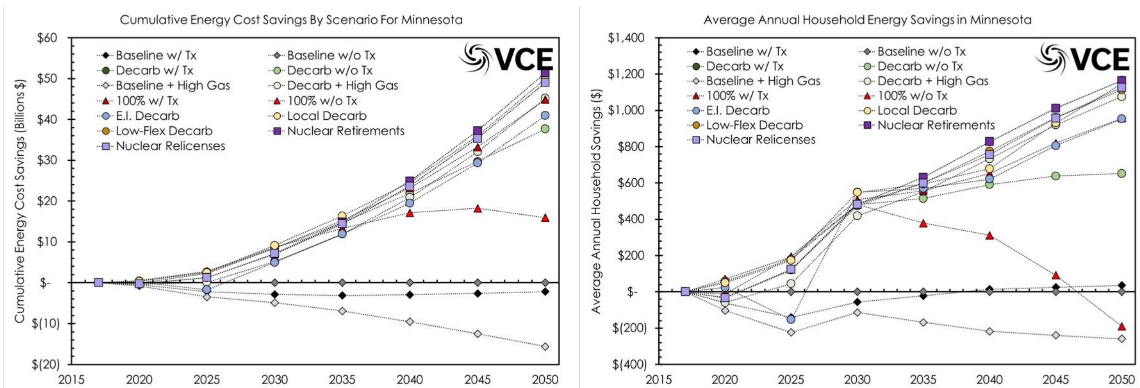


Figure 14: The cumulative energy cost savings (left) and average annual household energy savings (right) for Minnesota under each of the scenarios carried out in this study. The savings are created when compared with the baseline scenario with no transmission expansion allowed. Under two scenarios there is no cumulative savings by 2050. These are the baseline with transmission expansion and the baseline with high natural gas prices. The baseline with transmission expansion is closing the gap, in another 10 years the difference would be zero (time to pay back the transmission investments). For the high natural prices, the cost increases continue to grow with time. All the other scenarios result in large amounts of cumulative savings, up to $51 billion by 2050. The annual household savings show a similar characteristic, with generally increasing savings as time progresses.

Figure 14 demonstrates the extent of the savings possible with electrification and decarbonization. For all the decarbonization scenarios there are cumulative savings of between $15.9 and $51.4 billion. These savings are based on a comparison with the baseline scenario that does not allow interstate transmission expansion. The savings are computed using the input assumptions around what fraction of each sector is electrified and the spending that has transitioned away from the other sectors (primarily natural gas and gasoline). With higher natural gas prices in the baseline scenario there are additional costs to the Minnesota economy amounting to $15.6 billion by 2050 than with lower natural gas prices. This highlights another benefit of electrification and decarbonization: reduced exposure across the economy to higher fuel prices. The right panel of Figure 14 shows the same data, but represented as annual household savings. It shows that electrification and decarbonization provides a net positive for households in Minnesota. For the 100% without transmission expansion, the annual savings becomes annual costs due to the additional burden of removing the last 9% of emissions from the electricity sector. Notwithstanding the outlier of the 100% with no transmission expansion, the electrification and decarbonization scenarios could save Minnesotans an estimated yearly household spend on energy of between $653 and $1,165. Therefore, the 80% reduction of Minnesota economy-wide emissions by 2050 could be a net positive for the economy in Minnesota, since spending on energy could be reduced, freeing up capital to be invested elsewhere.

The next critical metric considered is the economy-wide greenhouse gas (GHG) emissions for Minnesota. In Figure 15, the GHG emissions for the entire Minnesotan economy and the emission rate for electricity generation are shown. The panels show that baseline scenarios do not create low enough emissions to achieve the 80% by 2050 goal. In fact, since baseline scenarios do not electrify other sectors, the emission reductions are limited to 30%. All scenarios reduce the carbon intensity of electricity; however, the electrification and decarbonization scenarios reduce the carbon intensity to below 50g / kWh. They achieve this, while also electrifying (and removing emissions from) other sectors. Figure 15 provides more evidence that electrification is beneficial in achieving the goal of economy-wide decarbonization. Under the baseline scenarios, the electricity grid reduces its carbon intensity by a factor of three. This reduction is based on economics alone. Therefore, electrifying sectors would provide a pathway to lower-emission power for those sectors. The process of electrification, in turn, provides additional demand for the electricity sector to invest capital against and, since the new loads could be more flexible, higher variable generation amounts can be added.

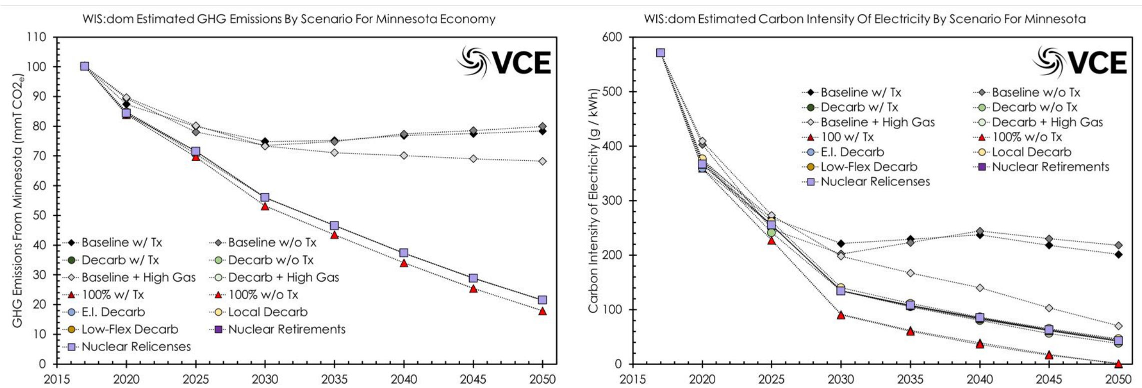


Figure 15: Economy-wide GHG emissions (left) and carbon intensity of electricity generation (right). It can be seen that the electrification and decarbonization scenarios produce much lower GHG emissions than the baseline scenarios. It demonstrates the potential of electrification because the electricity sector, in the baseline scenarios, lowers its carbon intensity by a factor of three by 2050, yet emissions for the whole economy only drop by ~20%. Further, under the high gas price scenario the decarbonization of the electricity sector is even more pronounced; however, that only results in 10% fewer economy-wide emissions. The electrification and decarbonization scenarios have a carbon intensity of 50g / kWh or lower for electricity.

Eight of the scenarios (the 80% by 2050 for Minnesota economy) follow almost exactly the same emissions trajectory, but their compositions in terms of deployed assets are very different. This is because WIS:dom has been set the same GHG emissions target to meet for those scenarios. As noted earlier, the costs and emissions from the majority of the decarbonization scenarios are relatively similar, therefore, there are numerous pathways to achieve the same overarching goal: a low-emission future at a low cost.

The decarbonization of the electricity sector (with and without electrification) happens with a transition away from coal-fired power plants, some dependence on natural gas, a large-scale build out of wind and solar generation, supplemented with storage, demand-side resources, and transmission. Nuclear power plants can contribute to zero-emission generation; however, cost is a constraint that manifests in nuclear losing installed capacity under most scenarios. The WIS:dom optimization model considers scheduled relicense dates and estimates the cost to relicense the nuclear plants for an operations extension of 20 years. Natural gas (or coal) with carbon capture and sequestration (CCS) is another technology option to lower emissions, but the costs and efficacy of this technology were not optimal (or selected by WIS:dom) in the decarbonization scenarios performed[18]. The CCS technology may be selected by WIS:dom if emission reduction targets were more aggressive, or the cost of CCS was lower than assumed.

Under all scenarios there is an increase in the installed capacity in Minnesota, as shown in Figure 16. The figure also displays the full-time jobs for each investment period to 2050. Since there is an increase in the total installed capacity (and the majority of the capacity comes from variable resources) there is a marked increase in the number of jobs. The difference in capacity build out is due to emission targets, transmission availability, and restrictions on flexibility / resource availability. The full-time job numbers are an output of WIS:dom, which uses the NREL Jobs and Economic Development Impact (JEDI) models as an input for many of the technologies[19]. There are some missing data for jobs, and VCE created input numbers for solar PV and rooftop solar PV jobs from publicly available data. Currently, these numbers do not include employment figures for energy efficiency, demand-side resources, or storage. These numbers would increase the employment rates seen in Figure 16 for all scenarios. Additionally, the full-time job numbers are only for direct and indirect jobs, and do not include any induced job numbers. Again, these induced jobs would increase the full-time job numbers further. These numbers were not included due to several factors: 1) Lack of reliable data for that industry; 2) WIS:dom was not explicitly computing the deployment, so could not track those values; or 3) too many variables would need to be considered to provide accurate input numbers for WIS:dom to calculate output values.

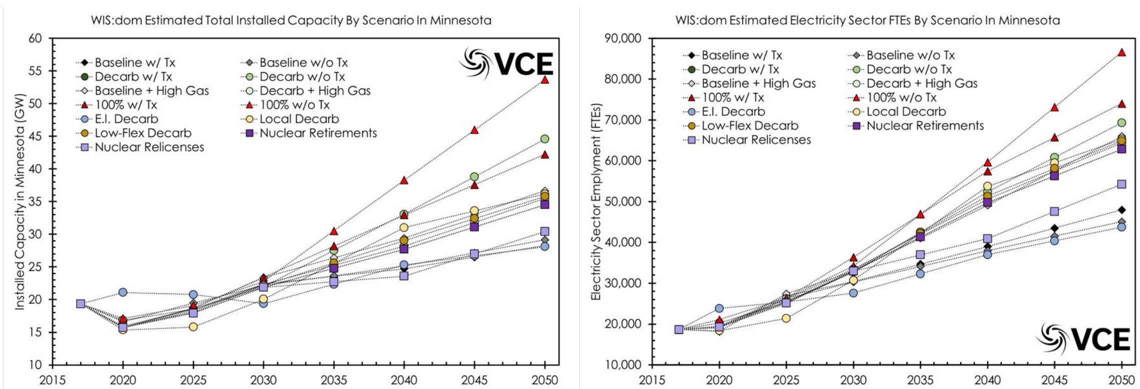


Figure 16: The total installed capacity (left) and full-time jobs within the electricity sector (right) for Minnesota. These jobs numbers include direct and indirect jobs for generation technologies. It does not include jobs for energy efficiency, demand-side resources, or storage (due to lack of reliable data points from within the industry). The job numbers are an output of the WIS:dom optimization model, which computes these from inputs provided by the NREL JEDI model for each state. Missing data is provided by VCE calculations (such as solar PV, and rooftop solar PV).

In summary, Figure 16 suggests that all pathways require increased installed capacity in Minnesota over the next three decades. The choice of technology mix will substantially alter the GHG emission reductions for the electricity sector and, in combination with electrification, alter the ability of Minnesota to meet its climate goals. In general, the electrification and decarbonization pathways creates more jobs and increases the installed capacity more than under the baseline cases. These new projects would increase tax revenue for Minnesota, which could be used to support the infrastructure spending required to accelerate the electrification of other sectors.

[18] The CCS was modeled with a cost of $1,098 / kW-installed incrementally added to natural gas combined cycle power plants. There was a fixed cost of $23 / kW-year and additional variable cost of $4 / MWh for the operation of the CCS component of the plant. Finally, the heat rate of the natural gas combined cycle plant was increase by 1,060 Btu / kWh if CCS were implemented. The CCS was assumed to have a negative CO_2 emission profile per MWh produced from the natural gas power plant that reduces the CO_2 emissions from burning the natural gas by 80%. It is assumed that other pollutants are reduced by 65% due to process of capturing the carbon.
[19] https://www.nrel.gov/analysis/jedi/models.html

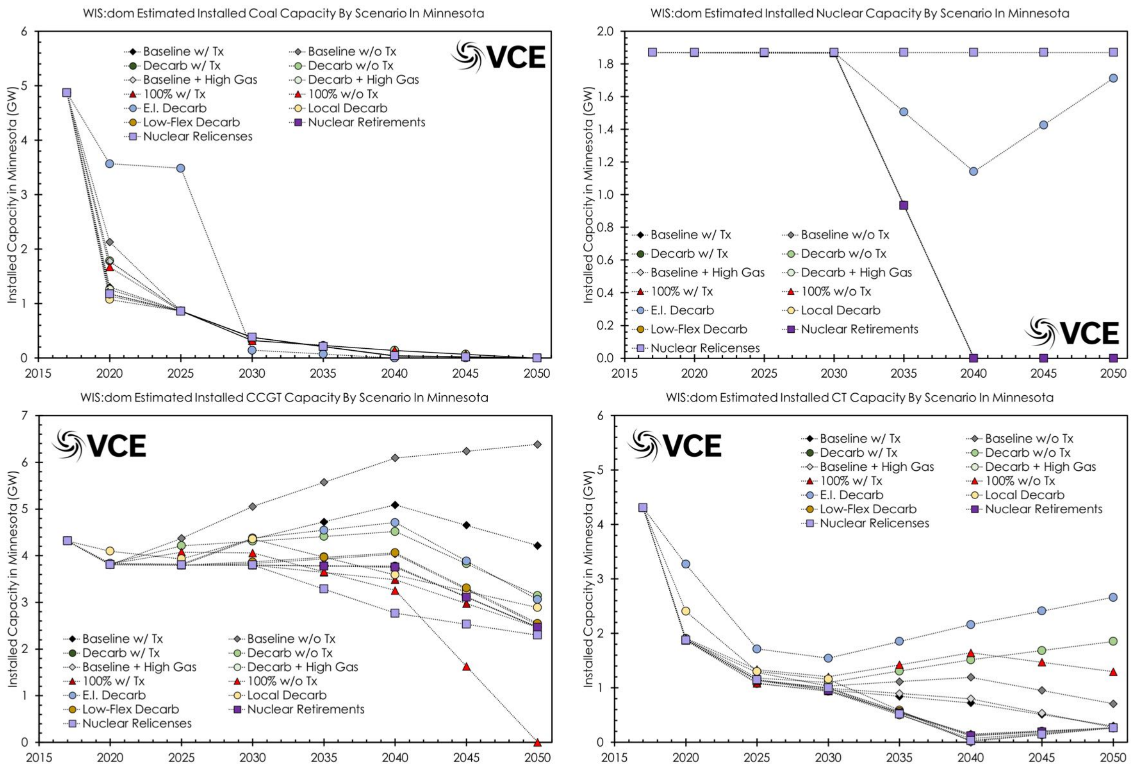


Figure 17: The thermal generation fleet in Minnesota for each investment period. Top-left shows that coal is retired almost completely in all scenarios by 2030. The top-right panel shows that for the majority of the scenarios it is assumed that nuclear power plants will retire with the relicense schedule. Only two scenarios are different. When the EI decarbonizes with Minnesota, new nuclear is built to replace retired generation. The other scenario has nuclear forced to relicense in WIS:dom. The Bottom panels display the changes in combined cycle (left) and combustion turbines (right). Combined cycle has varied capacity depending on scenario, with most seeing a reduction in capacity. For combustion turbines, there is a reduction in capacity for all scenarios, with tight grouping to 2030, but vary more heavily as time moves forward. The CTs and CCGT plants complement the variable resources, but still emit GHGs.

Figure 17 shows the thermal generation fleet for Minnesota for each scenario pathway through 2050. Coal-fired power plants are almost entirely retired by 2030, regardless of scenario. Nuclear power plants are retired with relicense schedule for most scenarios (constraint within WIS:dom). New nuclear is only built in the scenario where the Eastern Interconnection electrifies and decarbonizes along with Minnesota. Another scenario has WIS:dom enforce nuclear relicense through 2050.

Under baseline scenarios, new natural gas (combined cycle) power plants are built in Minnesota to cover demand growth. Under all other scenarios natural gas plant capacity falls. In fact, most scenarios group around 2,000 - 3,000 MW of natural gas combined cycle by 2050, compared with 4,000 - 6,000 MW in the baseline scenarios. It should be noted that WIS:dom is optimizing across the entire Eastern Interconnection, so some of the capacity within Minnesota can be shared with outside regions (and compete in the MISO market). The capacity of natural gas combustion turbines is reduced in every scenario from 2017 levels. This is partly driven by WIS:dom having detailed knowledge of the weather-patterns for every 5-minutes for an entire year for each investment period and partly from its ability to site new generation more appropriately to reduce the burden on the entire system[20]. Since WIS:dom is considering all generation simultaneously (co-

[20] This is very different to siting new generation at the lowest LCOE [levelized cost of electricity] locations. WIS:dom determines the placement of all generation but, in particular, variable generation that minimizes the system costs. Therefore, it may be more cost effective to construct a, for example, wind farm at a slightly more expensive site (in terms of LCOE), because when it competes in markets it might generate more revenue due

optimized) and is computing the dispatch, it can more accurately reflect the capacity needs of the system and how the new generators might contribute to that resource adequacy. The capacity of combustion turbines (CT) are similar for all scenarios to 2030. For the decarbonization scenario that allows transmission expansion reduces the capacity of the CTs further towards zero. When the Eastern Interconnection decarbonizes with Minnesota, the capacity of CTs increases to support much higher wind and solar buildout over the MISO (and SPP) footprint. In 2050, the installed capacity of CTs is non-zero for all scenarios (at least 200 MW). This is because WIS:dom recognizes the need for planning reserve margins and CTs can provide inexpensive capacity that could be dispatched in extreme conditions to ensure reliability.

In Minnesota, there is approximately 220 MW of hydroelectricity power plants. The WIS:dom optimization model has the ability to expand hydroelectricity plants up to twice their current capacity (assuming upgrades to turbines and other efficiency gains); however, WIS:dom is limited by the run-off water conditions provided by the detailed weather data inputs. WIS:dom can dispatch hydroelectricity with market signals, but must not exceed its installed capacity. If WIS:dom decides not to dispatch the hydro plant for any reason, it must release the water downstream that it would have done under normal operation. This constraint ensures that other uses for the water are not impacted by hydro plant ramping. The ramping of hydropower can be used by WIS:dom to accommodate more variable resources. Nevertheless, under all, but one, of the scenarios hydro remains unchanged throughout the optimization period. For the localized decarbonization scenario, the capacity of hydropower is increased to 440 MW to provide local generation of clean power. WIS:dom finds it more economical to use hydropower as a baseload generation source as much as it can.

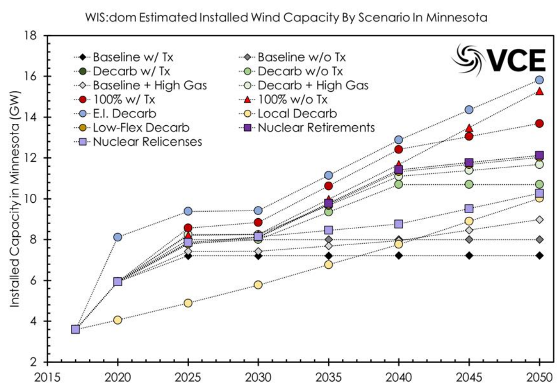


Figure 18: The installed capacity of wind turbines in Minnesota for each scenario. All scenarios increase the installed capacity of wind to at least 7,200 MW. Slower adoption occurs for the local decarbonization scenario, while the fastest adoption occurs when the EI decarbonizes with Minnesota. The lowest installed capacity occurs for the baseline scenarios, while the electrification and decarbonization scenarios have an installed capacity of between 10,000 MW and 15,800 MW by 2050. The WIS:dom optimization model includes the expiration schedule of the PTC (and ITC). The installed capacity is almost fixed between 2025 and 2030, but afterwards capacity climbs. This is driven by the electrification of new loads that are more correlated with wind power generation.

In Figure 18, the installed capacity of wind power is displayed for all the scenarios. It suggests that a minimum of 7,200 MW of wind is economic in Minnesota regardless of carbon emission goals and expiration of the production tax credit (PTC). To proceed above that level, electrification comes into play. The electrification of the new demands has a temporal component that is more correlated with wind than traditional demands. For example, space heating demands are highest when temperatures are lower, which occur more frequently in winter and overnight hours. These correlate well with wind power production, which is greatest in the colder seasons and in evening

to its power production patterns, there could be less requirement to provide supporting infrastructure for that wind farm, and the additional transmission capacity necessary for the new plant could be utilized by other assets on the system. These effects can combine to reduce the overall cost of the system more than if a new wind plant was sited at the least-cost LCOE wind site.

hours. In addition, the decarbonization drives more investment into the low-emission technologies, which further increases the capacity of wind power. For the electrified and decarbonized scenarios, the installed capacity of wind by 2050 ranges from 10,000 MW and 15,800 MW for Minnesota.

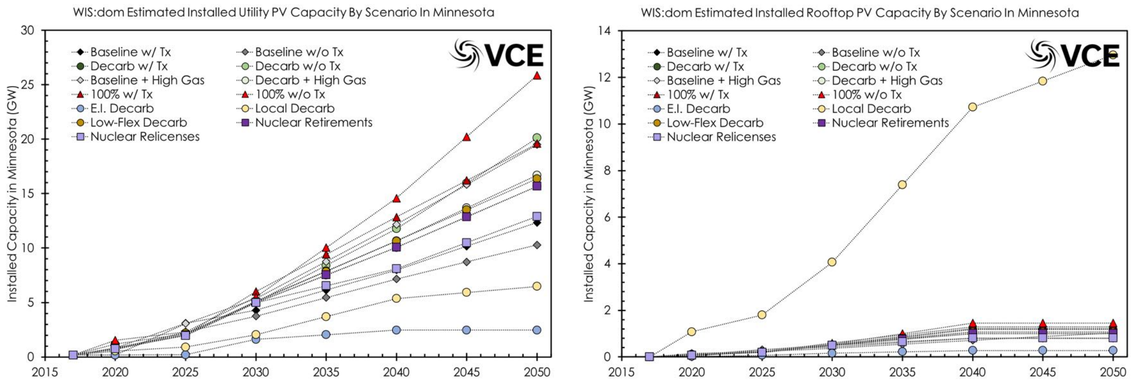


Figure 19: The installed capacity of utility-scale solar PV (left) and rooftop solar PV (right). All scenarios have increased capacity of solar PV. The baseline scenarios have a higher installed capacity for utility-scale PV than two decarbonization scenarios, both EI and localized decarbonization. The EI decarbonization reasoning is based around more wind on the system and solar PV installed in other parts of the EI. For the local decarbonization, the capacity is transferred to the rooftop solar PV sector. By 2050, the combined solar installed ranges between 2,700 MW and 27,300 MW. The highest capacity occurs when Minnesota requires 100% decarbonization of the electricity sector, and the lowest is when the EI decarbonizes with Minnesota.

The installed capacity of solar PV is categorized into two subgroups. The first is utility-scale PV and the second is rooftop solar PV. The two categories are treated separately within WIS:dom. Rooftop solar PV has an impact on local load due to positioning of the panels, while utility-scale PV can be fixed, 1-axis, and 2-axis tracking panels (depending on the economics of each resource site). Under all scenarios solar PV installed capacity for Minnesota increases (as shown in Figure 19). Figure 19 shows that the baseline scenarios have more utility-scale solar capacity than two decarbonization scenarios. This is due to very different reasons. The baseline scenario utility-scale solar PV installed capacity is higher than in the EI decarbonization scenario because Minnesota has access to more wind power generation that can be shared across MISO (and the EI). The baseline scenario utility-scale solar PV installed capacity is higher than in the localized decarbonized scenario because the installed capacity is transferred to rooftop solar PV. For the majority of scenarios approximately 1,200 MW of rooftop solar PV is installed in Minnesota. The pathways are more varied for utility-scale solar PV, but at least 2,700 MW are installed by 2050. This installed capacity could reach as much as 27,300 MW in the 100% decarbonized electricity sector scenario. Most scenarios cluster between 10,000 MW and 20,000 MW. The range of values for the installed capacities demonstrates the various combinations of generation that could supply the required electricity for decarbonization of the Minnesotan economy by 2050.

In addition to generation, the WIS:dom optimization model can deploy energy storage technologies. These technologies are characterized as assets that change from being demands to generators. When the storage is charging it is recognized as a demand in WIS:dom, and when it is discharging it is recognized as a generator. The storage assets are deployed only when doing so reduces the cost of electricity or provides services that are required to meet constraints at a lower cost than alternatives. There are two components of the storage that are important for WIS:dom to track and optimize: the power input/output (kWs) required and the amount of energy stored (kWhs). Therefore, WIS:dom does not predefine the storage duration (e.g. 4-hours storage), rather WIS:dom computes the peak charge and discharge rates that are required along with the capacity of energy storage necessary to provide reliable power without fail, at a cost that is lower than other alternatives. For example, WIS:dom could choose to dispatch demand-side resources over building more energy storage capacity (or vise-versa). For the scenarios conducted for this study it was found that storage is beneficial regardless of pathway. As can be seen in Figure 20, the power and energy needs are different for each scenario.

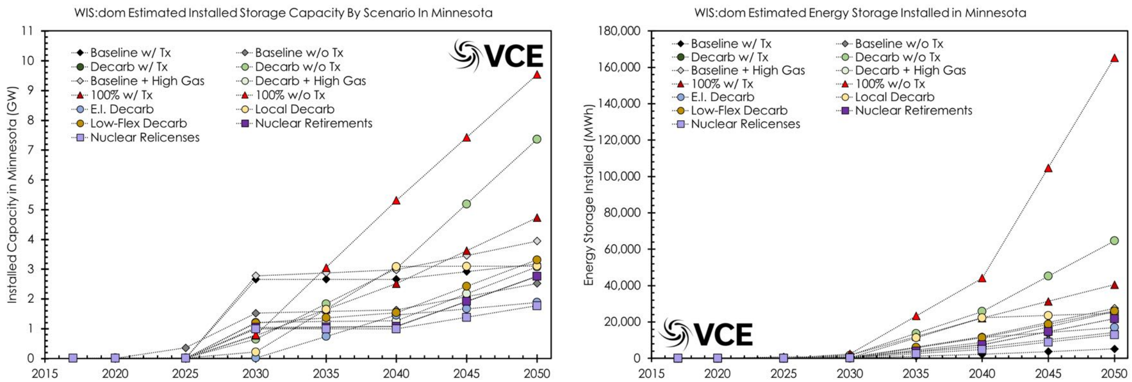


Figure 20: The installed capacity of storage, separated into peak power capacity (left) and energy storage capacity (right). By 2035, all scenarios have some energy storage installed. In fact, all but one scenario has energy storage deployed by 2030. More storage is required when there is no additional interstate transmission allowed and when emission reductions are deeper. The amount of energy storage capacity (kWh) is drastically increased when 100% decarbonization (w/o Tx) or local decarbonization is considered. The maximum amount of deployed storage was 9,500 MW with 17.5 hours at max output. The majority of decarbonization scenarios require approximately 2,000 – 3,000 MW with 450- – 550-minute (7.5- – 9.2-hour) duration of energy storage.

In Figure 20, it can be seen that energy storage becomes an important component of the electricity system for all scenarios by 2035. The amount of storage required for different scenarios varies, but in general more storage is utilized when there are deeper emission reductions and transmission is restricted. This applies to both power and energy storage values. In the extreme, with complete decarbonization of the electric sector, electrification, and limited transmission expansion, WIS:dom installs 9,500 MW of energy storage with 17.5-hour duration. For the vast majority of the electrification and decarbonization scenarios, 2,000 to 3,000 MW with 7.5- to 9.2-hour duration storage adequately provides the necessary services to provide power for each 5-minute interval for an entire year by 2050. The storage technologies increase the overall demand on the system while reducing (or eliminating) negative costs because they can alleviate transmission congestion, absorb over-production of power and dispatch to cover lower generation periods. The WIS:dom optimization model prefers to assign storage to be a system-wide asset, rather than a competing generation asset. The reasoning is two-fold: 1) The whole electricity system can benefit from storage being available and when a certain amount of storage exists on the grid the arbitrage that a generation asset would survive on would be largely removed, thus sharing the costs over the whole system keeps the asset available for all customers and generators, while keeping system costs down; 2) If the asset were considered more akin to a transmission asset it could be deployed by the RTOs or balancing authorities to assist with events that might not otherwise be compensated for. For example, storage could provide capacity to a system, but only if it has stored energy; however, it may receive market signals to dispatch at a specific time, and if it does so it might not be available at a later time when the system requires more services. Thus, under a generation asset paradigm the storage would not be able to assist; but, in a transmission asset paradigm, the storage could hold reserve amounts of electricity for extreme events, help with faults on the system or absorb electricity generation / demand spikes. Regardless of the paradigm required for storage to be valuable, the scenarios show that more of the technology on the system is helpful in lowering overall costs and reducing emissions.

Another asset that is considered by WIS:dom for all the scenarios for deployment is transmission. There are two forms of transmission considered by WIS:dom, interstate and intrastate transmission. Using existing transmission topology, a reduced form model is produced that computes the interstate and intrastate transmission. The interstate transmission must carry electricity across state borders, while intrastate remains entirely within the state. For all the scenarios performed the intrastate transmission is increased by the installation of new generation capacity and providing power reliably at 5-minute intervals of dispatch. For interstate transmission, there are more restrictions. While intrastate transmission must be paid for, it is allowed to be constructed if required for supporting generation; the same is not true for interstate transmission. For interstate transmission, it is sometimes forbidden to be constructed. Further, it is included in the capital expenditure limits within WIS:dom (which defines the total amount of investment that can happen in the electricity sector). The interstate transmission, when allowed to expand, increases its capacity between Minnesota and surrounding regions by 1,500 – 3,000 MW of export capacity and 8,000 MW import capacity. WIS:dom computes the need for capacity expansion of transmission based upon economics and reduced form transmission topology with neighboring regions. The power flow along transmission lines is tracked by WIS:dom and electric losses are computed for each 5-minute interval along each of the corridors, which is a function of temperature, wind speed (and direction), line loading, and the composite conductance and susceptance properties of the lines.

V. Scenario Specific Results

In this section, emphasis will be placed on the differences between scenarios. If a topic is discussed in an earlier scenario, but not in a later one, then the scenarios have been deemed to have similar characteristics (in a broad sense) as the earlier scenario. The summary spreadsheets with the most important metrics (and accompanying images) will be available at the time of release of this report.

Every scenario has exactly the same outputs from WIS:dom, and so each spreadsheet and image set for every scenario contains the same data and information, with the values changing between scenario results. Thus, for each image shown in the current section, there is a counterpart for all the other scenarios for comparison.

a. Baseline

The baseline scenario is based on economics. There are no carbon taxes assumed. As with all the scenarios WIS:dom is solving over the entire US portion of the Eastern Interconnection. There are two branches to the baseline scenario, one with interstate transmission expansion allowed and one where it is not. Figure 21 displays the installed capacity for both branches for all the investment periods.

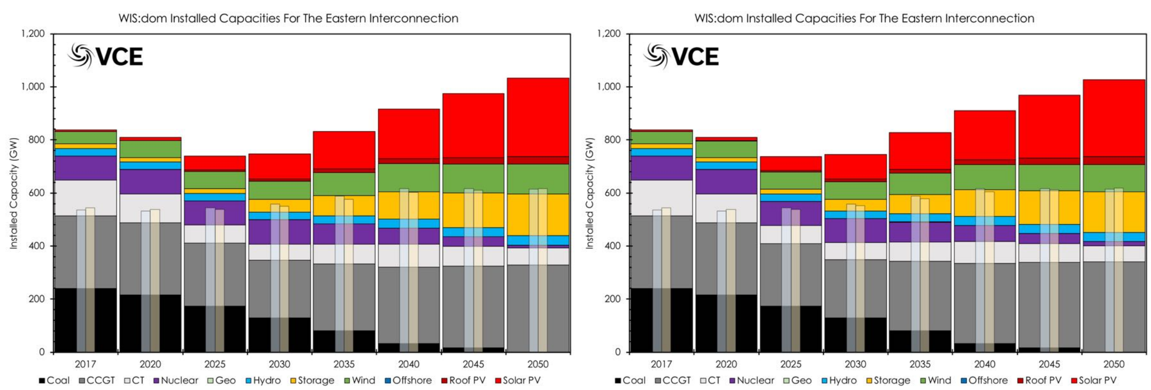


Figure 21: The installed capacity across the US portion of the Eastern Interconnection for the two branches of the Baseline scenario. The left panel is for the branch that allows interstate transmission capacity expansion (w/ Tx), while the right is for the branch that does not allow interstate transmission capacity expansion (w/o Tx). In the w/ Tx branch, there is more variable (and less thermal) generation present by 2050. The transparent bars within the columns (blue and yellow) represent the peak average hourly demand for that investment period. The blue is the input demand peak, while the yellow is for the WIS:dom determine demand peak. Note that by 2030 the peak demand is above the synchronous generation, because WIS:dom can deploy portfolios of asynchronous generation, storage, DSM, and transmission to provide robust balance between supply and demand for each 5-minute interval.

Figure 21 illustrates the evolution of the electricity grid in the Eastern Interconnection from 2017 to 2050 under economics (and current policies, with their expiration schedule). The overall trend is a diminishment of baseload generation sources (coal and nuclear), with an increasing dependency on natural gas power plants in conjunction with wind and solar generation (supplemented with storage). The electricity system becomes more flexible due to faster ramping technologies (storage and natural gas) and zero-marginal-cost variable generation. These trends are supported by recent history in the electricity grid transformation[21]. The cost projections for natural gas fuel remain low throughout the optimization horizon, while reductions in wind and solar costs drive

[21] https://www.eia.gov/todayinenergy/detail.php?id=36092

further investment in those technologies as time progresses (even with the expiration of PTC and ITC). The baseline transition estimated by WIS:dom reduces GHG emission and other pollution from the Eastern Interconnection electricity system by around 40% compared to 2017 levels (Figure 22). The methane (CH_4) emissions reduce until 2030 then level off at a reduction of 20%. This is due to the transition from coal to natural gas, which results in more of this powerful GHG being emitted compared with carbon dioxide trends. Other dangerous localized pollutants are considerably reduced by removing coal-fired power plants from the electricity system. Direct $PM_{2.5}$ and PM_{10} are almost entirely extinguished by 2050.

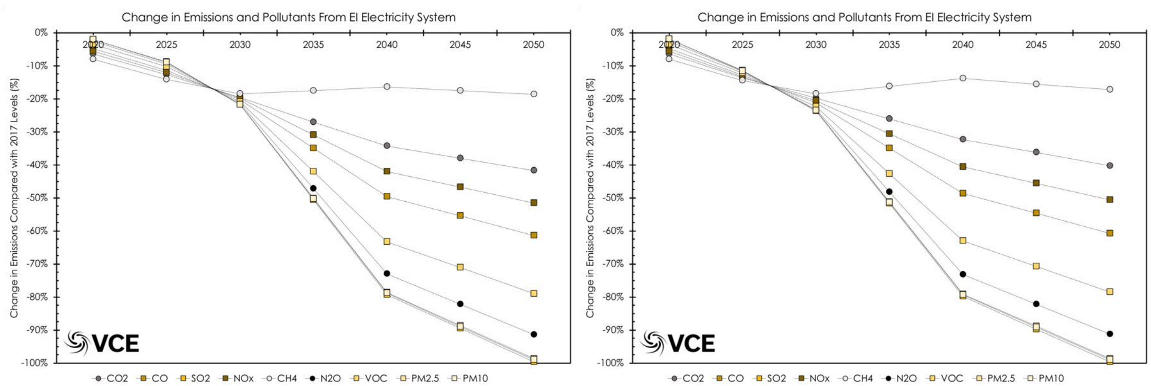


Figure 22: The GHG emissions and other pollution from the Eastern Interconnection (left, w/ Tx; right, w/o Tx). The evolution of the electricity system results in a 40% drop in carbon dioxide emissions by 2050 (from 2017 levels). Most pollution trace the carbon dioxide emission reductions, but noticeably CH_4, methane, emission reductions level off at 20% reduction by 2030. This is because coal has been replaced, in large part, by natural gas and incomplete combustion results in more emissions from this powerful GHG.

In Figure 23, the state-level installed capacities are shown for the six investment periods for the w/ Tx branch of the Baseline scenario. The figure illustrates the spatial heterogeneity of the Eastern Interconnection electricity system. Each state within the Eastern Interconnection is represented and has a unique load profile, existing generation mix, and potential resource. The figure also depicts a future pathway with baseload generation being replaced with near-zero-emission variable resources complemented with natural gas. Some states are more reliant on natural gas under the baseline scenario, such as the South-East states. Most states have storage technologies deployed by 2050. To retire power plants from the system, WIS:dom must do so in a way that reduces the cost of the system. Therefore, if there is capital outstanding on a power plant, the model must repay this. If the power plant has repaid all its capital investments, to remove the power plant, WIS:dom must find a portfolio of alternatives that are lower in cost than the fixed and variable operational costs of the old plant. Thus, WIS:dom is making investment decisions that reduce the cost of electricity the most during each investment time period.

Figure 24 shows the electricity generation share by technology for each investment period. It shows that the generation mix is transitioning away from baseload generation to flexible natural gas and variable generation. Due to the assumed depressed natural gas prices throughout the optimization, it dominates the generation share by 2050 as it absorbs the reduced shares of coal and nuclear. Of course, wind and solar generation also consume some of the generation share left by coal and nuclear, but their share is lower than that of natural gas. Figure 25 also demonstrates the exposure that the electricity system could have to fluctuating natural gas prices. With such a large share of the generation mix by 2050, the entire electricity sector would be extremely sensitive to any increase in the price of natural gas fuel.

Figure 25 displays the winter dispatch of the Eastern Interconnection, while Figure 26 shows the dispatch for the summer of each of the investment periods out to 2050. The dispatch is average hourly numbers from the 5-minute dispatch performed by WIS:dom. The images aggregate all the generation of each type for that hour. In addition, the plots show how the demand-side is altered by the WIS:dom optimization model. The alterations come from storage demand and the demand-side resources available to WIS:dom. At each 5-minute interval, WIS:dom must balance generation, transmission losses, load-following reserves, storage charging/discharging with its associated losses, demand-side resource dispatch, market prices, and fuel consumption / limitations. It is clear from Figures 25 & 26 that the Eastern Interconnection electricity system is estimated to be completely different by 2050 compared with the one that existed in 2017.

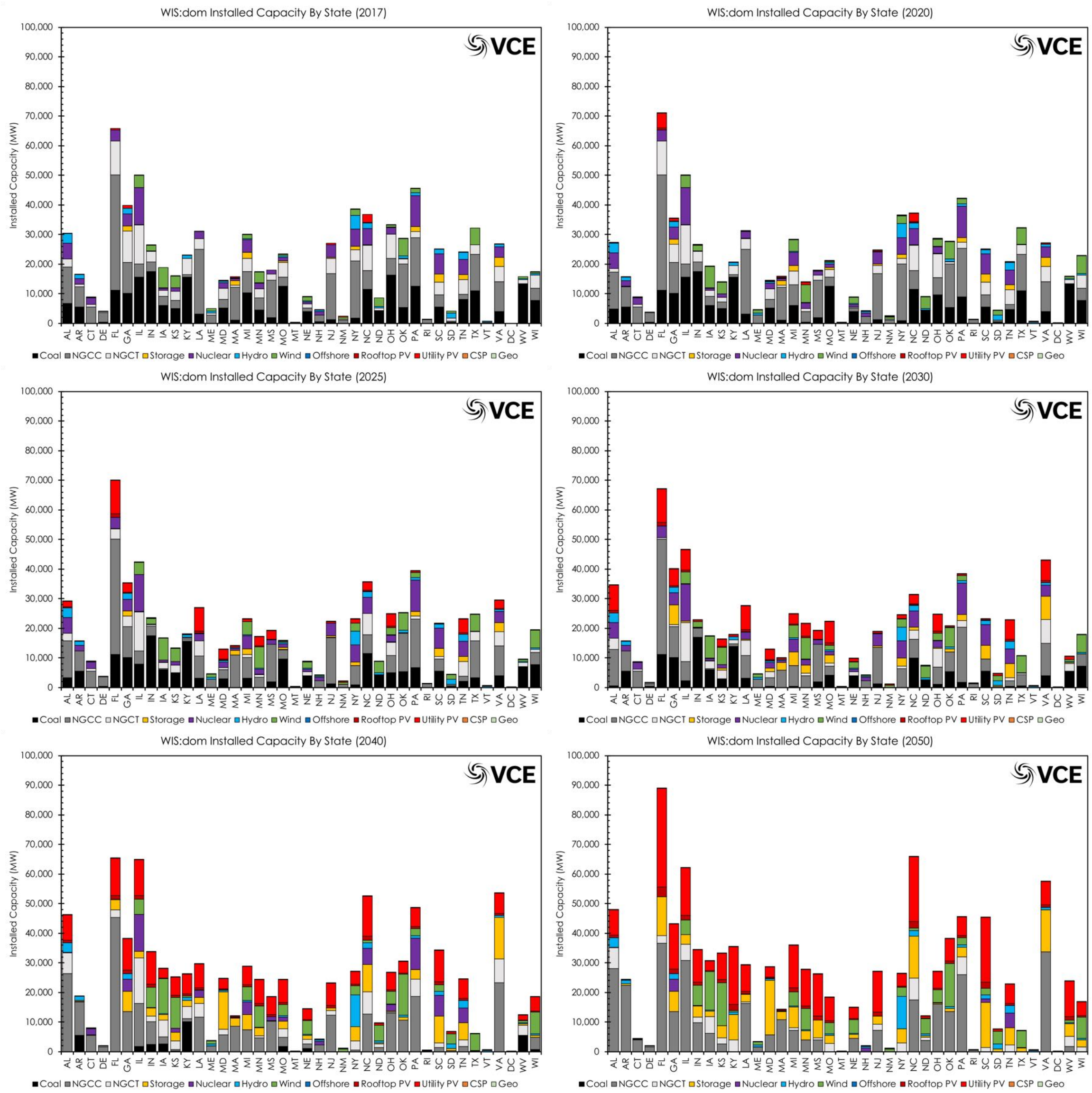


Figure 23: The installed capacity for each state in the Eastern Interconnection for each investment period optimized by the WIS:dom model. The evolution of the electricity grid can be followed from the top-left (2017) to the bottom-right (2050). The system in 2050 is dominated by natural gas, solar, wind and storage. That system is completely different to the coal and natural gas dominated system in 2017. As the generation capacity mix changes, the WIS:dom optimization model must adapt and find a way to have all the resources work in a way that provides reliable power for each 5-minute interval for a full year.

The general feature of Figures 25 & 26 is the flexibility of natural gas and storage to provide the necessary ramping capabilities for solar PV to provide electricity while the sun is shining. Indeed, storage shifts the traditional peak to when solar peaks (shifting it earlier in time) as it charges, in anticipation of the net peak that occurs at sunset. The flexibility of these resources absorbs the longer-duration cycles in wind power. The reduction in nuclear power (as a clean electricity source) is noticeable throughout the dispatch stacks to 2050. Some of the power is replaced with variable resources, but some is absorbed by natural gas power.

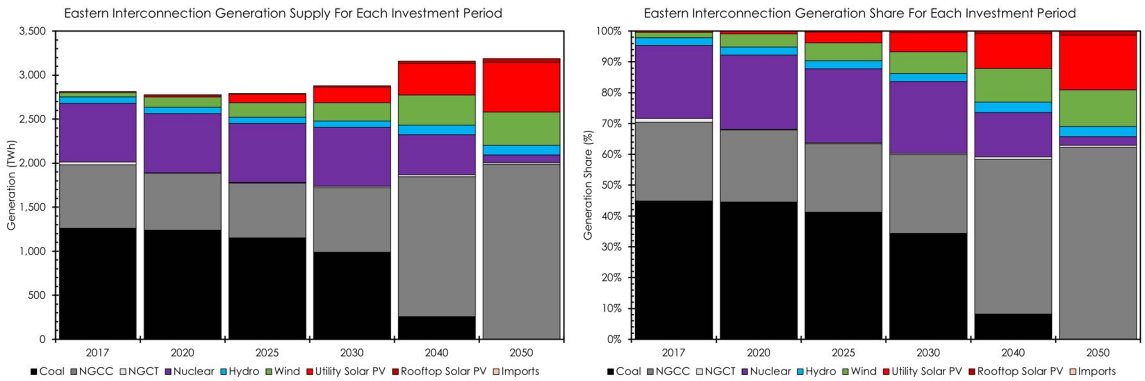


Figure 24: The estimated generation mix for each investment period in the Eastern Interconnection. The left panel shows the total electricity production in TWh, and the right panel shows the percentage of generation by technology. The system in 2050 is dominated by natural gas generation. The remaining share is primarily from wind and solar. With such a skewed generation mix, the system is exposed to high risks of fuel cost changes.

Another important illustration from Figures 25 & 26 is that baseload generation is clearly not necessary as a concept. The WIS:dom optimization model finds resource mixes that can provide reliable generation at 5-minute intervals without fail. Further, the model does this while providing over 7% of load-following reserves at all times (through spinning reserves in the natural gas power plants, down-dispatched wind and solar power, and storage). The WIS:dom optimization model also maintains the NERC planning reserve margins[22] across the whole footprint.

[22] https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

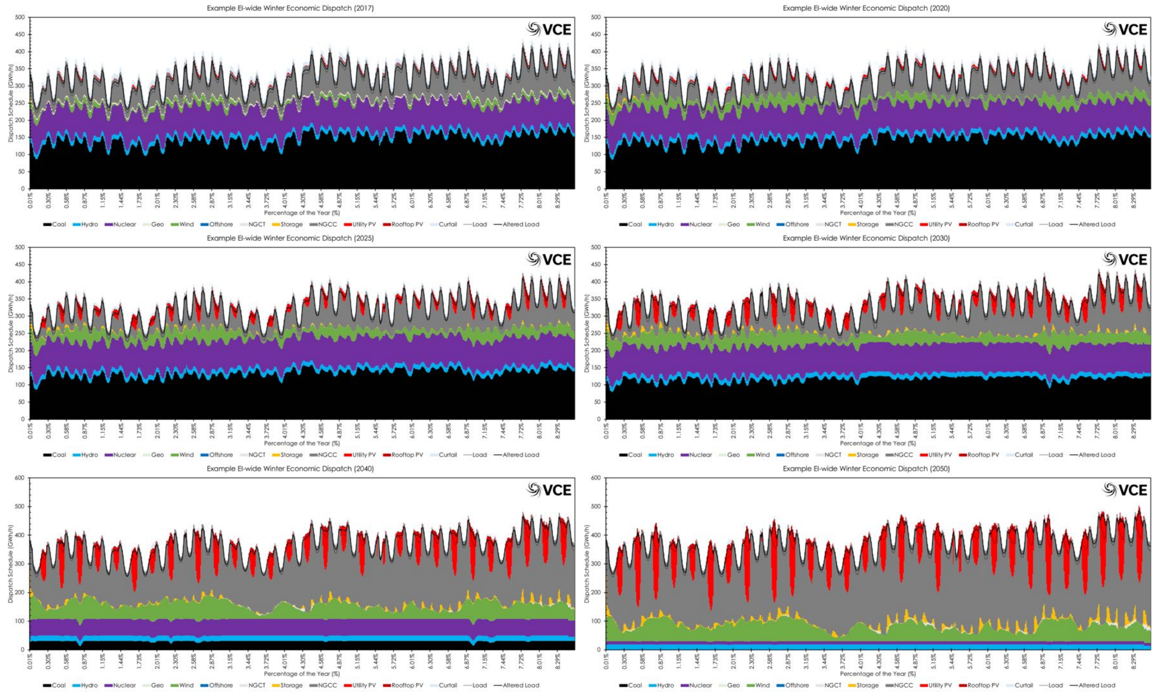


Figure 25: The economic dispatch stack for January for each investment period in the Eastern Interconnection. The evolution of the electricity grid can be followed from the top-left (2017) to the bottom-right (2050). The cycling of storage and natural gas is clear by 2050, when solar squeezes out other generation when it appears. Notice the altered load that is enabled by storage and demand-side resources.

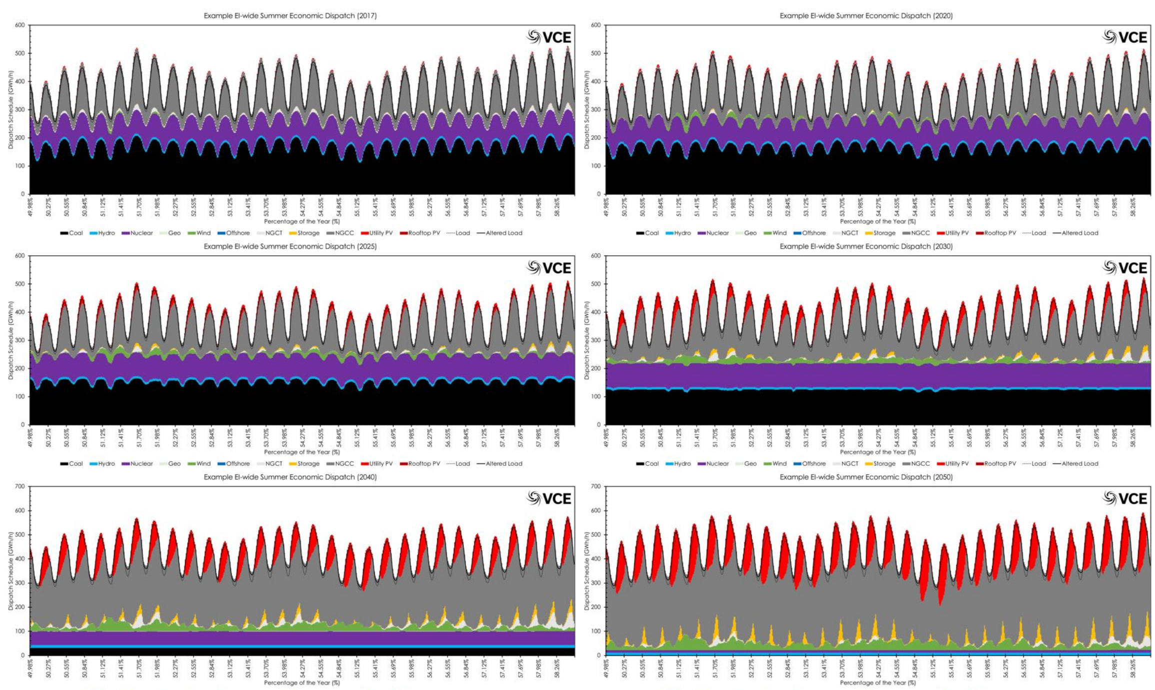


Figure 26: The economic dispatch stack for July for each investment period in the Eastern Interconnection. The evolution of the electricity grid can be followed from the top-left (2017) to the bottom-right (2050). In the summer months the dispatch is centered around the solar being used as peaking for the traditional load peak, and then natural gas and storage dispatching to fill the new net peak that appears at sunset. Also, the altered load enables charging of the storage to coincide with the solar peak.

An additional benefit that comes from the transition to more variable generation and flexible generation is the modularity of the system. Weather-driven generation varies more predictably and slowly than large-scale baseload generation (if they go offline). This benefit is reduced in this baseline scenario because there are large-scale natural gas power plants constructed, but as newer plants are built these will be more flexible and have higher availability.

One benefit of using WIS:dom is its ability to co-optimize different resources and time-horizons to reduce the overall system costs, while ensuring demand and supply balance over every 5-minute interval. For the Baseline there are two branches that treat interstate transmission differently. Figure 27 displays the aggregate interstate transmission capacity in terms of import and export capacity for each state in the Eastern Interconnection.

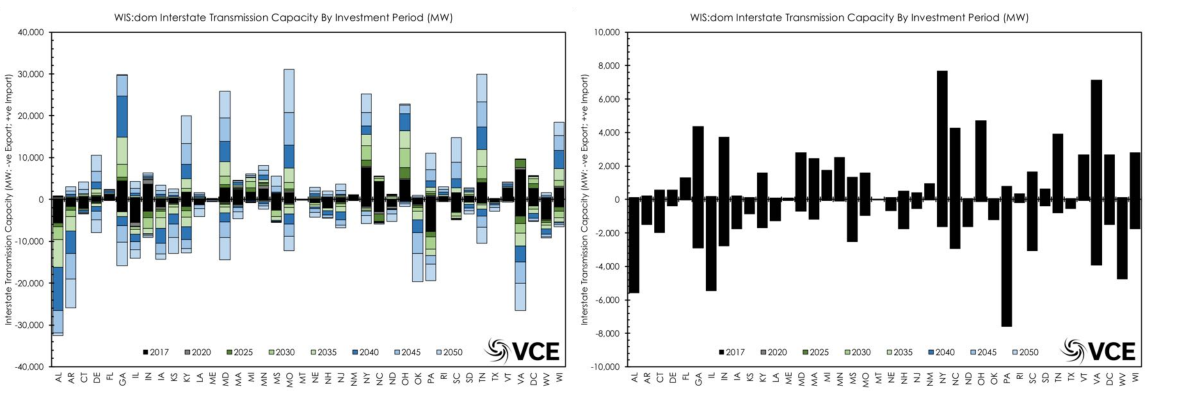


Figure 27: The import (positive) and export (negative) capacity for each state within the Eastern Interconnection. The left panel is for the w/ Tx branch and the right is for the w/o Tx. The right panel shows that WIS:dom fixed the import/export capacity for each state to the value estimated for 2017 for the w/o Tx branch. The interstate transmission buildout is substantial in the left panel. The new transmission enables more resource sharing and cooperation between regions. It reduces curtailments and provides access to lower-cost resources. Note that the majority of the transmission capacity expansion occurs in the 2040 to 2050 timeframe, which is due to construction times and variable generation being built.

In Figure 27, the biggest construction in transmission is completed in the 2040 to 2050 timeframe. This is driven by construction time, variable generation coming online, and the retirement of plants enabling a shifting of resource locations and higher levels of resource sharing. The right panel in Figure 27 is the estimated 2017 interstate transmission capacity, which is fixed for the w/o Tx branch. Referring back to Figure 21, the difference in transmission does not dramatically alter the installed capacities; however, it alters its dispatch and the ability for WIS:dom to invest in different siting that is more robust over time.

While computing the capacity expansion and economic dispatch of the electricity system, WIS:dom must determine the spatial siting of each power plant. This is performed at a 3-km resolution. In general, each power plant generator unit of similar type within a 3-km grid cell is aggregated together with average characteristics of all the units within that grid cell. For focus regions (such as Minnesota), each individual power plant is described. Limitations to the construction of generators and transmission are provided to WIS:dom as exogenous variables. Therefore, WIS:dom can compute the best locations to build new generation (and transmission) to supply the electricity grid. Each 3-km grid cell has characteristics with respect to cost of interconnection, existing transmission and substations, and transmission loss functions to supply local and distant demands.

Figure 28 demonstrates the ability of WIS:dom to consider the geographic siting of generation, storage and transmission. The siting of generation, particularly wind and solar, provides WIS:dom with new temporal evolutions of power production. These new time-series are used by WIS:dom to determine if the new siting provides a net benefit to the electricity grid. If not, WIS:dom will not select the site. Essentially, WIS:dom can automatically determine the benefits of spatial diversity across electricity grids. In addition, the 5-minute intervals for the generation profile provide detailed descriptions of the potential electricity resource available. WIS:dom can recognize patterns in the correlation shapes for variable generation and exploit those correlations, while avoiding their possible disadvantages.

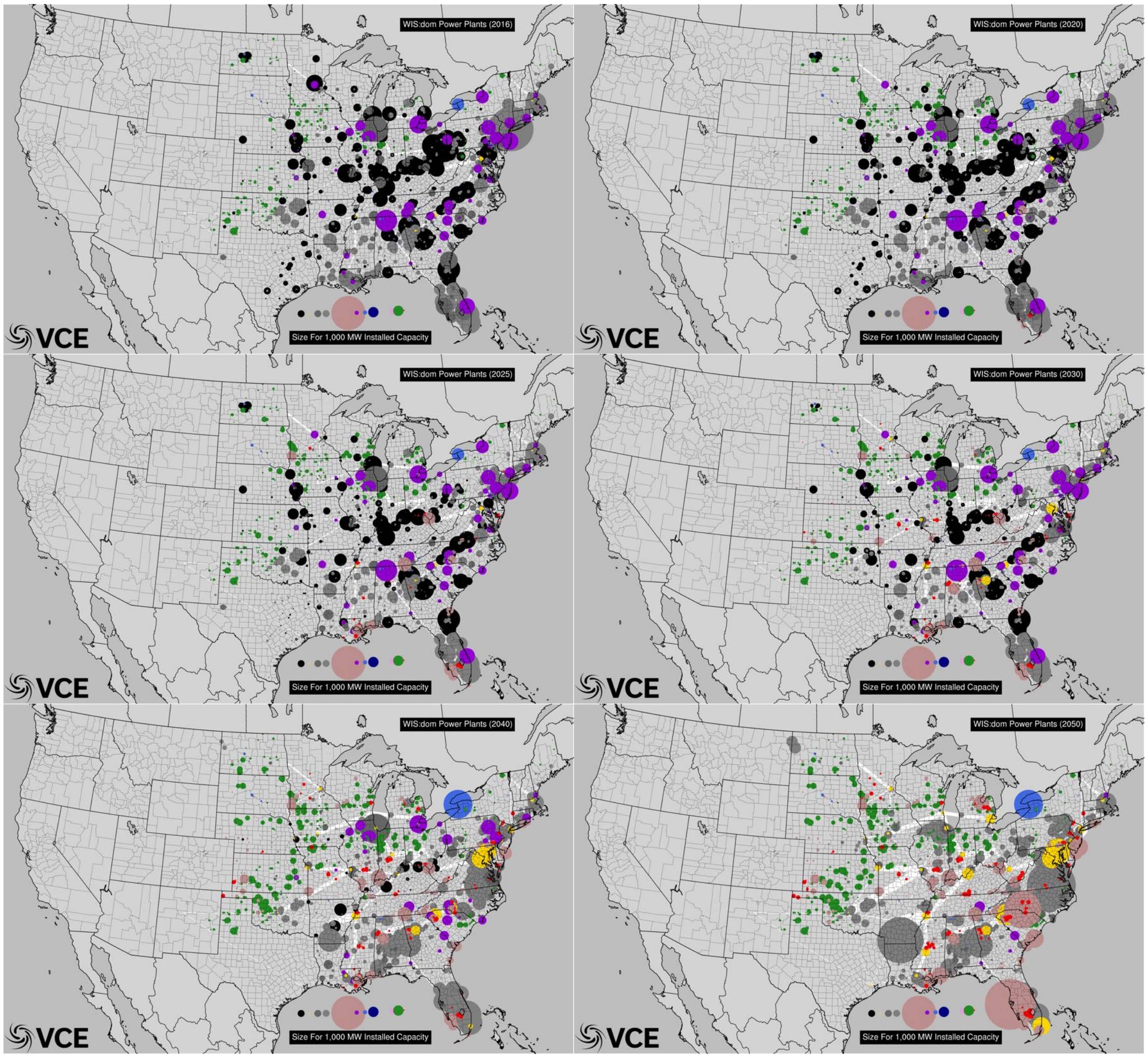


Figure 28: The geographic siting of generation created by WIS:dom for the Baseline w/ Tx scenario branch. The investment periods can be followed from 2017 in the top-left panel to 2050 in the bottom-right panel. The white lines represent the interstate transmission capacity. The thicker the lines the greater the capacity. The colors are (in order shown at bottom): black = coal, yellow = storage, dark grey = NGCC, light grey = NGCT, rose red = rooftop solar PV, purple = nuclear, light blue = hydroelectric, dark blue = offshore wind, pink = geothermal, green = onshore wind, red = solar PV.

Interestingly, Figure 28 depicts a transition in the electricity sector comprising two, seemingly apposed paradigms: more remote, utility-scale, variable generation; and more localized distributed generation with demand-side resources. The storage tends to gravitate to high demand centers. The portfolio of utility-scale variable generation, distributed generation, transmission, storage and large-scale natural gas is the economical pathway for the Eastern Interconnection, absent any climate mitigating policies. It appears that across the entire Eastern Interconnection footprint coal-fired power plants retire in order of their economics and regions that they can sell the most power to, i.e. more isolated (vertically integrated markets) coal-fired power plants retire the fastest, while plants in regions surrounded by large, integrated markets remain for longer.

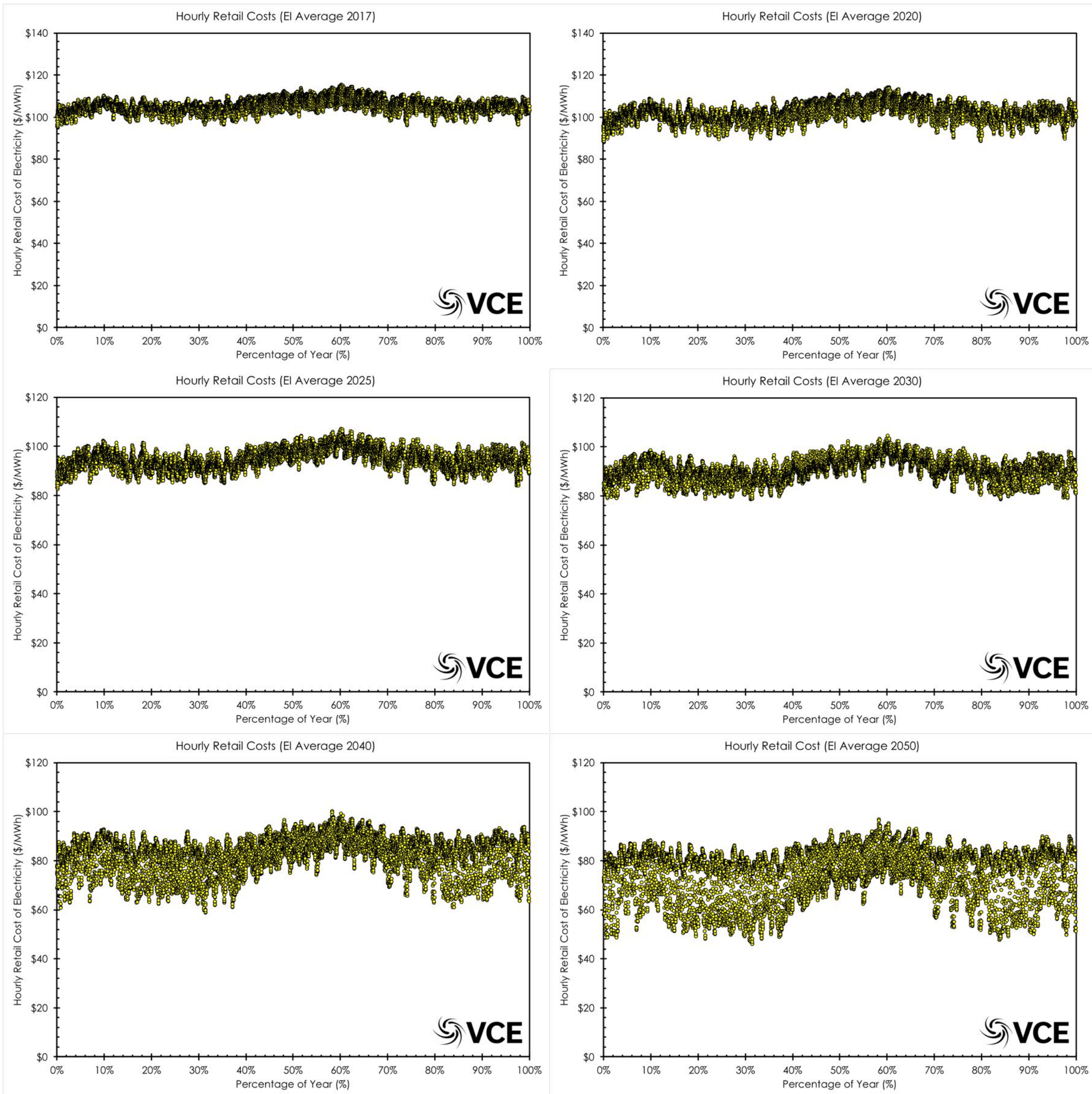


Figure 29: The average retail cost of electricity for each hourly interval across the Eastern Interconnection. The retail cost represents the average cost to provide electricity to all the customers across the entire footprint. It does not represent the rate structure that a customer is charged. It is the equivalent of a real-time Time of Use (TOU) rate structure. With each investment period the cost of electricity is experiencing downward pressure due to the low-cost variable generation and cheap, abundant natural gas fuel.

Figure 29 depicts the average hourly retail cost of electricity. The "cost" represents the average cost to deliver electricity to all customers over the Eastern Interconnection over twelve, 5-minute intervals. It illustrates the downward pressure on real-time costs for electricity; when demand is lower, and variable generation more abundant, the cost of electricity falls. From the perspective of WIS:dom, if costs are low enough, more resources could be deployed (storage, transmission, or demand-side resources) to increase demand at some time periods (increasing prices) and then dispatch the system differently at high-price constrained time periods. Due to this process, the negative price signals do not emerge. By definition, WIS:dom must charge for electricity over a year such that all generators make a profit. Further, WIS:dom must pay for all transmission construction, storage capacity, and any demand-side resources dispatched.

The present study is focused on Minnesota, and while the influence from outside the state must be analyzed, the evolution of the Minnesotan electricity grid is the primary metric considered. In Figure 30, the installed capacity and full-time jobs for Minnesota are shown for both Baseline scenario branches.

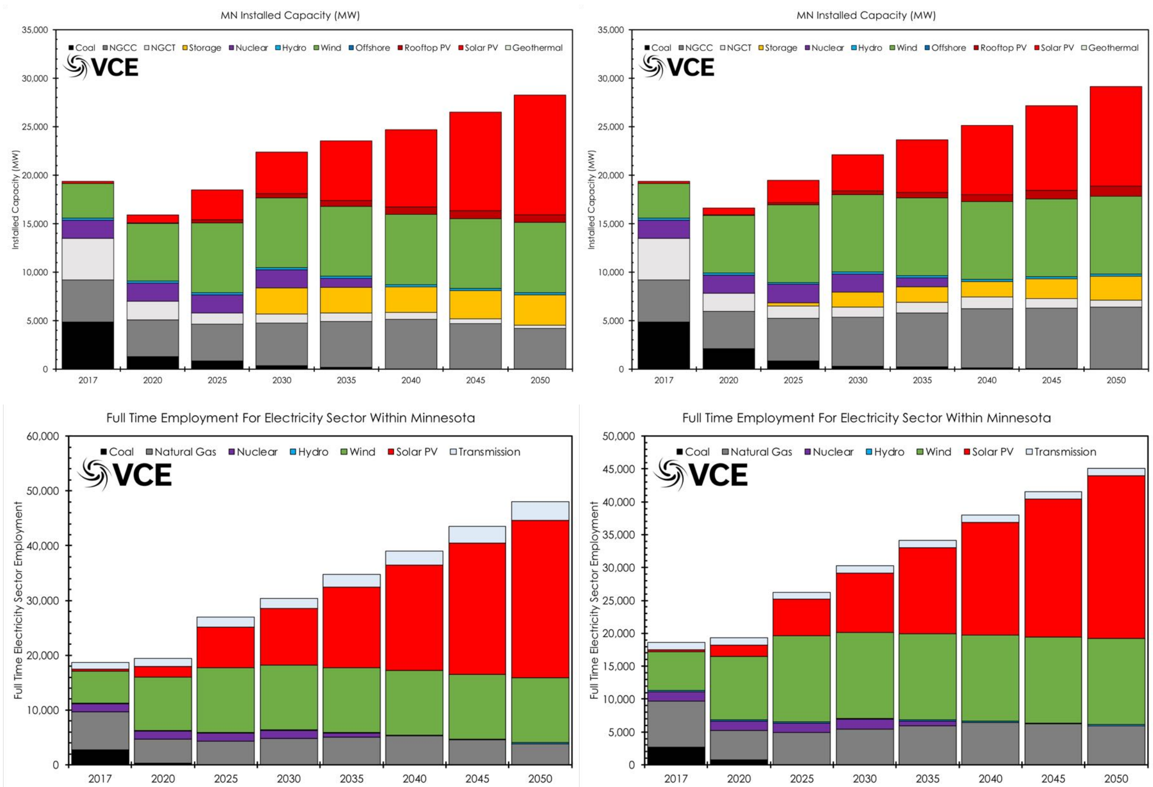


Figure 30: The installed capacities (top) and full-time jobs (bottom) for the Minnesotan electricity sector. The left panels are for the w/ Tx branch, while the right panels are for the w/o Tx branch. More natural gas and wind is deployed when interstate transmission is constrained. When transmission expansion is allowed, more storage and solar PV is brought online reducing the need for natural gas combined cycle and combustion turbines. More jobs are created when transmission expansion is allowed, and solar connects to the grid, at larger capacities, earlier.

Figure 30 suggests that allowing transmission, even in a baseline scenario, increases the amount of variable generation installed. Further, the transmission enables more storage to come online, more solar PV construction, and a marked reduction in natural gas dependency. The transmission enables Minnesota to interact more with the surrounding regions (particularly MISO), which allows WIS:dom to combine resources in a cost-effective manner and reduce the need for natural gas power plants. This implies that considering more than just the focus region (Minnesota) multiplies the pathways available for resource combinations and can automatically reduce the dependency on fossil-fuel generation. If a considered planning region is smaller, there are less resources available to consider.

With the higher share of variable generation constructed in Minnesota, Figure 30 shows that the number of jobs also increases. The higher numbers of jobs are simultaneous with lower-cost electricity and a cleaner grid.

Figure 31 displays the generation share for Minnesota for each investment period for the Baseline w/ Tx branch. The dispatch stack includes imports from out of state that provide power to the

Minnesotan consumers. The import and exports are monitored by WIS:dom, so that GHG emissions can be attributed to the purchasers of electricity that was generated with fossil-fuels. Local pollution is attributed to the generation site, but since GHG emissions are global it is important to determine when the electricity is consumed and apply those emissions to the demand site. Figure 31 shows that Minnesota can transform from a fossil-dominated grid to one dominated by variable generation.

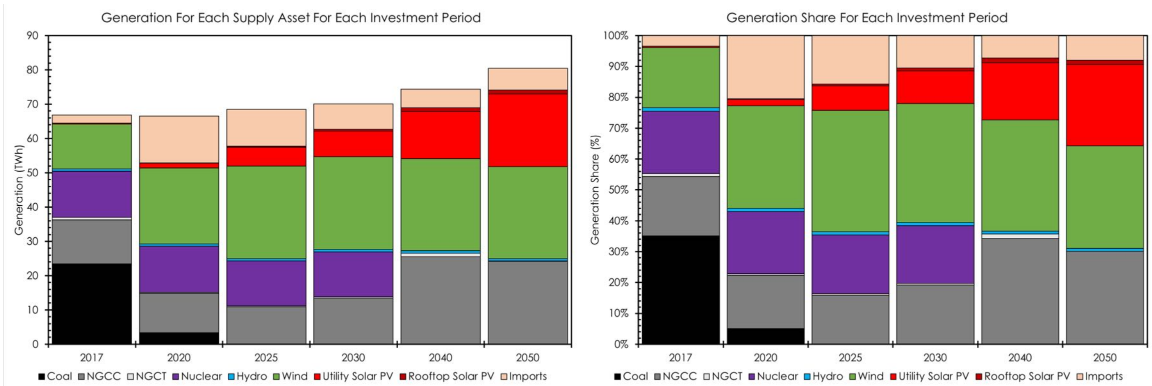


Figure 31: The generation share by investment period for Minnesota for the Baseline w/ Tx scenario. The left panel displays the total generation in billions of kWhs, or TWh, and the right panel shows the percentages. The generation share transitions from fossil-dominated to variable generation dominated. Further, imports are removed from Minnesota in the longer-term and replaced with exports into MISO; producing economic benefits for Minnesota.

Figures 32 and 33 display example dispatch stacks output from WIS:dom for Minnesota for the month of January and July for each investment period. The panels show how WIS:dom coordinates the dispatch of variable generation through seasons at high-temporal frequency.

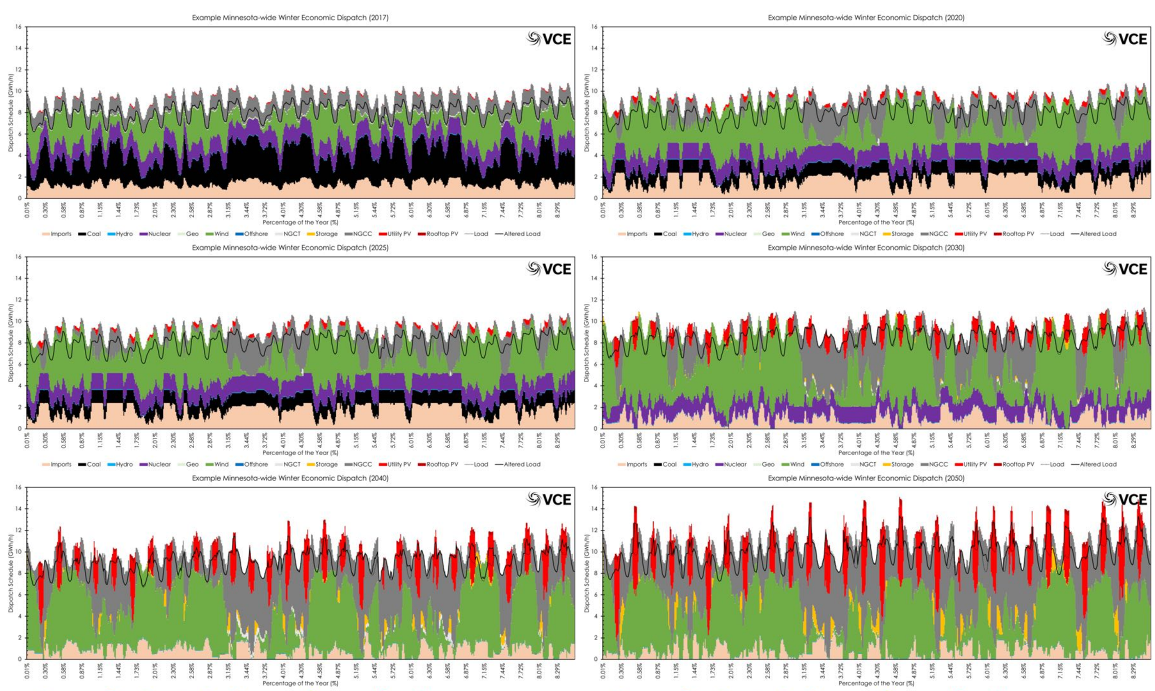


Figure 32: The economic dispatch over the month of January for Minnesota for each of the investment period. WIS:dom finds combinations of generation and demand-side resources for each 5-minute interval for all of Minnesota to keep electricity flowing throughout each investment period.

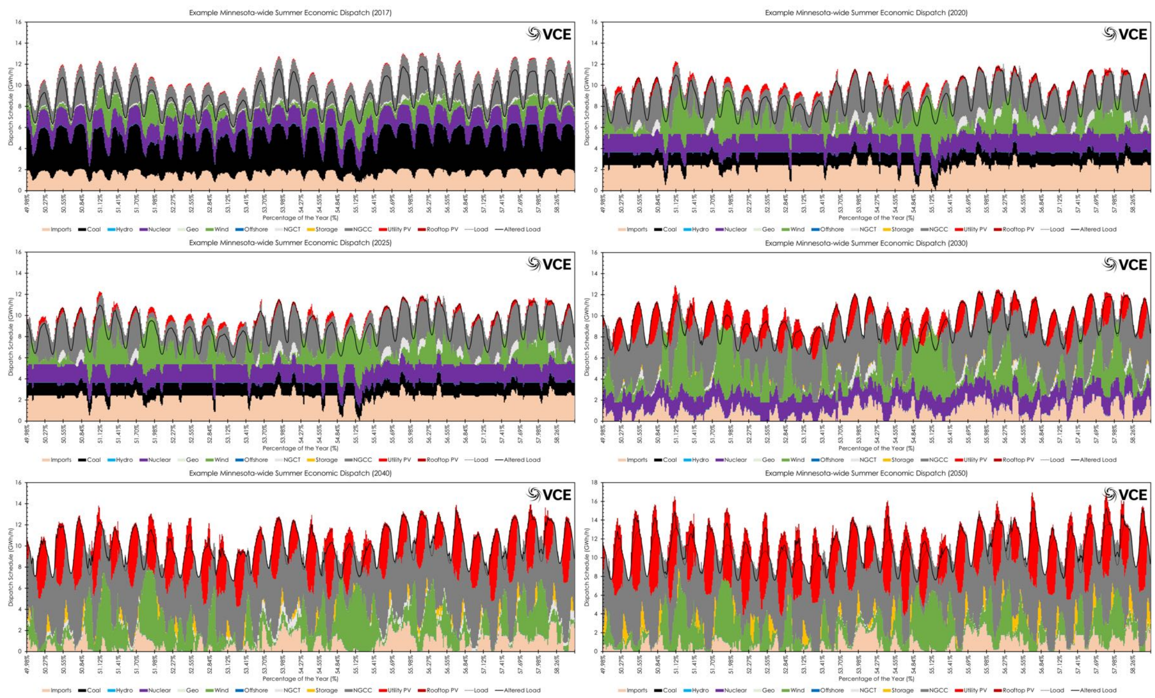


Figure 33: The economic dispatch over the month of July for Minnesota for each of the investment period. WIS:dom finds combinations of generation and demand-side resources for each 5-minute interval for all of Minnesota to keep electricity flowing throughout each investment period.

The dispatch stacks in Figures 32 and 33 demonstrate that power can be reliably provided by a portfolio of technologies working in coordination. They also illustrate the seasonality of wind and solar with varying penetration levels. In summer (July), solar provides much more power and energy than in winter, while the inverse is true for wind; it provides more power and energy in winter (January). This weather-driven anti-correlation helps wind and solar reinforce each other (if siting can be carried out efficiently).

It is clear from Figure 31 that the electricity mix is not 100% variable generation for any investment period, yet during the time-series represented in the dispatch stacks there are numerous occasions where the instantaneous level of variable generation is 100% and above. These instances occur in all seasons. This demonstrates that achieving 100% instantaneous variable generation occurs well before a 100% variable generation mix is achieved.

One more metric that is tracked by WIS:dom is carbon dioxide emissions for each state. As noted before, the consumer of the electricity is responsible for emitting the GHGs. In Figure 32, the cumulative carbon dioxide emissions for each state is shown. It illustrates the emission characteristics of the Eastern Interconnection electricity grid and shows the relative contribution to the total emissions from each state. For Minnesota, it suggests that under the baseline scenarios cumulative carbon dioxide emissions by 2050 (from 2017) could be 700 million metric tons. Figure 32 also illustrates that Minnesota is a part of a larger system that influences and impacts the role that Minnesota and its targets can have on total emissions. There are two avenues for progress that Minnesota can impart: 1) Being a leader and demonstrating the viable pathways to low-emission futures for the state itself; and 2) initiate an evolving paradigm where planning is performed considering other areas and how they may have to evolve around states that are taking action to reduce emissions; which may end up altering their grid performance in terms of revenue and competitiveness, if they themselves do not also adapt.

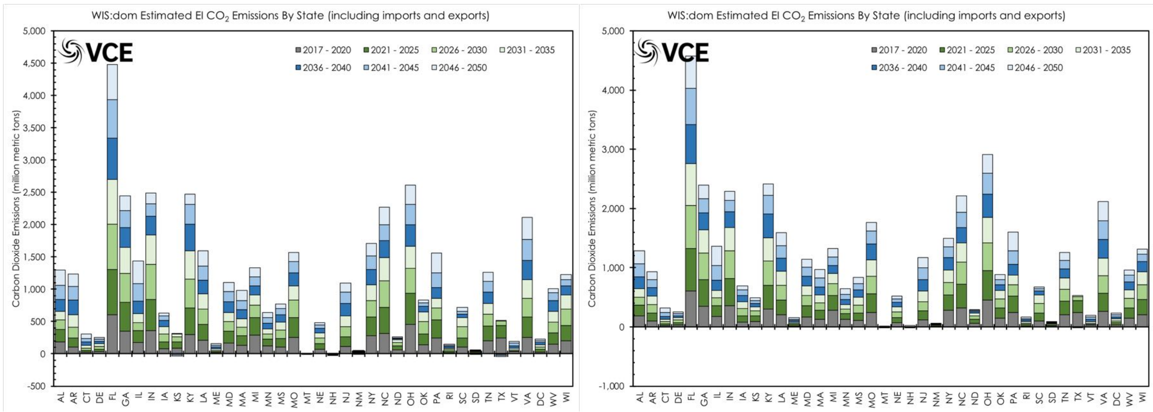


Figure 32: The cumulative carbon dioxide emissions for each state within the Eastern Interconnection. The left panel is for the Baseline w/ Tx branch and the right is for the w/o branch. The colors represent the emissions during each investment period from 2017 to 2050. When emissions are negative, it means that the state is exporting enough electricity that has carbon dioxide emissions attributed it that the state has a net deficit of emissions. Those negative emissions will appear on the importing state's inventory of emissions. Therefore, the net contribution is zero (i.e. WIS:dom is avoiding double counting GHG emissions).

The Baseline scenario is the pathway against which all other pathways in this study will be compared. The reasoning behind this is that the future is uncertain and the Baseline scenario gives a pathway of a possible future where WIS:dom makes all decisions based upon economics only, while the other scenarios will have additional constraints imposed upon them. Since different pathways are compared within a single modeling framework (WIS:dom) the differences can be evaluated in a rigorous, uniform, manner. For example, if WIS:dom is deficient in a particular area, all model scenarios will be deficient in the same area, and so its impact will be the same across all pathways.

The following scenarios will only have the metrics and features that substantially change compared with the baseline discussed and analyzed.

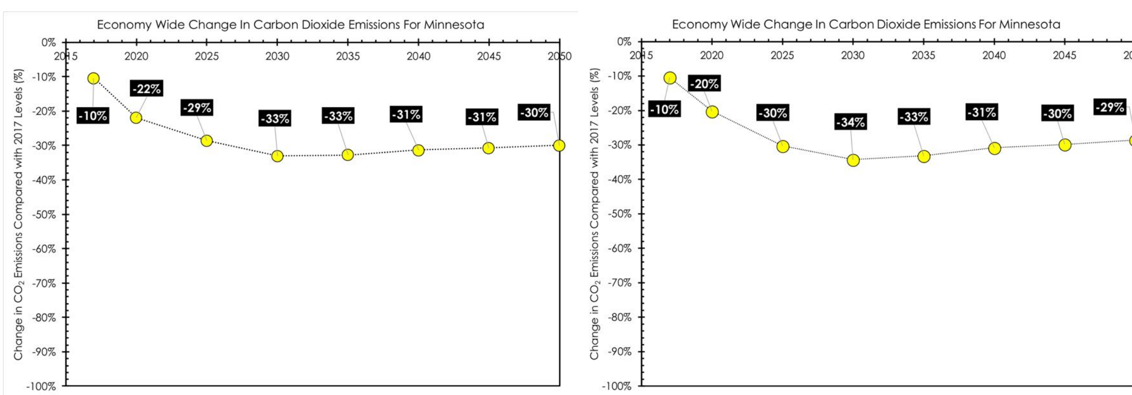


Figure 33: The carbon dioxide emission reductions for the entire Minnesotan economy. It shows that by 2017 the reduction from 2005 has reached 10%. By 2050, both branches reduce emissions by another 20%. With emission reductions essentially ceasing by 2030.

b. Minnesota deep decarbonization

The Minnesota deep decarbonization scenario had two branches: one that allowed interstate transmission capacity expansion (w/ Tx), and one that did not (w/o Tx). In this scenario, the rest of the Eastern Interconnect evolved along the *Baseline scenario* pathways, while Minnesota electrified and decarbonized its economy to achieve 80% reductions, from 2005 levels, in GHG emissions by 2050. The scenario pathway suggests that Minnesotans could save a cumulative \$37.6 billion or \$51.4 billion if electrification and decarbonization were carried out. The lower value is for the branch that does not allow interstate transmission and the higher amount is for more interconnection with neighbors. In other words, the cumulative value of transmission expansion by 2050 under the MN deep decarbonization scenario is \$13.8 billion. These saving are calculated in comparison with the Baseline without transmission capacity expansion scenario branch. These cumulative values translate to an average annual saving for each household of between \$653 and \$1,165 by 2050. Figure 34 displays the investment period cumulative savings along with the average annual household savings.

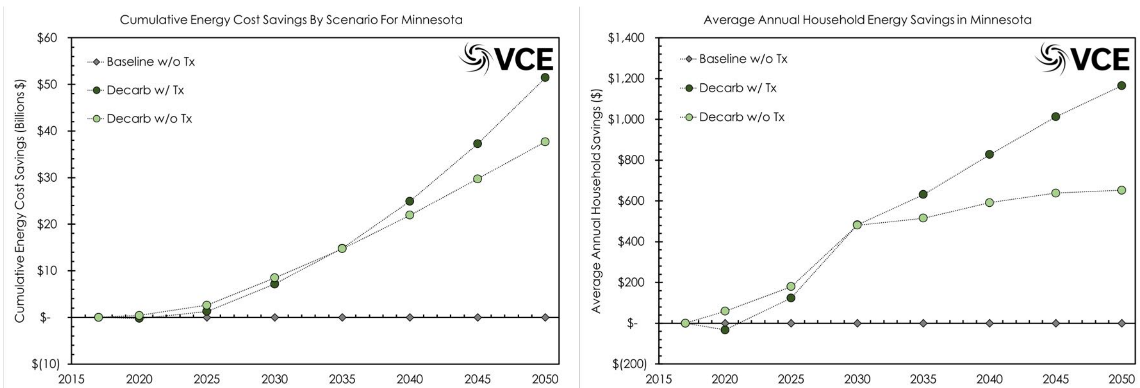


Figure 34: The cumulative energy savings (left) and the average annual household savings (right) for the MN deep decarbonization scenario. The expansion of interstate transmission costs slightly more by 2020, but by 2030 the cost savings overtake the non-transmission-expansion branch, resulting in almost \$14 billion more in energy savings.

The MN deep decarbonization scenario requires the reduction of economy-wide emissions to below 80% of those in 2005. Figure 34 shows that this electrification and decarbonization generates energy cost savings. The carbon dioxide emission reductions for the electricity sector (for all states) and the entire economy is shown in Figure 35.

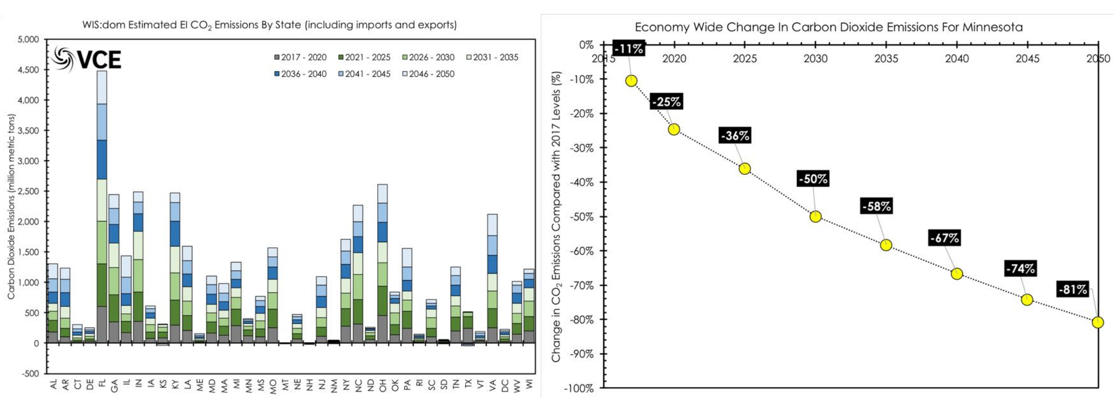


Figure 35: The electricity sector emissions for all states in the Eastern Interconnection (left) and the Minnesota economy-wide emissions reductions from 2005 levels (right). Comparing the left panel with Figure 32, it can be seen that the emissions from the electricity sector are substantially reduced. While comparing the right panel to Figure 33, it can be seen the economy-wide emissions are reduced by a further 50% beyond the baseline scenario. These panels are for the w/ Tx branch.

Figure 35 demonstrates the potential of electrification and decarbonization working together. The left panel shows Minnesota electricity is becoming cleaner (compared with Figure 32), while also removing 50% more emissions from the entire economy (compare right panel of Figure 35 with Figure 33). Note that the remaining states in the Eastern Interconnect are not impacted unduly by the electrification and decarbonization of Minnesota.

Minnesota is altered through electrifying and decarbonizing the generation mix. Figure 36 shows the installed capacity and full-time jobs for the w/ Tx branch. The figure shows that total installed capacity is approximately 6,000 MW more than in the Baseline scenario. Additionally, there are about 15,000 more full-time jobs created. The primary changes are higher wind and solar PV installations with fewer natural gas power plants.

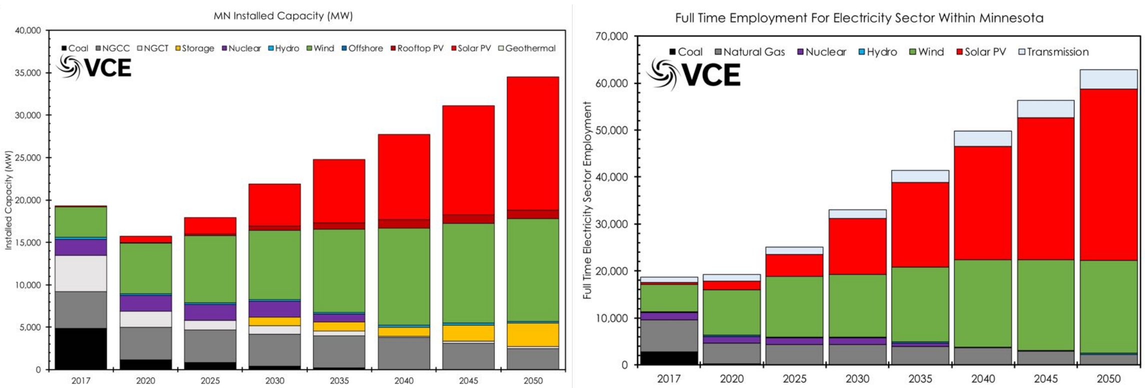


Figure 36: The installed capacity (left) and full-time jobs (right) for Minnesota. Comparing these panels with those in Figure 30, it can be seen that total installed capacity has increased by approximately 6,000 MW. Additionally, over 15,000 more full-time jobs have been created. There is a marked increase in wind and solar PV installations, with accompanying reductions in natural gas power plants.

The amount of storage for this scenario, as seen in Figure 36, was at the same level as in the Baseline scenario. When interstate transmission capacity is limited, the amount of storage increased three-fold. The storage installations come in-lieu of the spatial advantage that the transmission infrastructure provides. Alongside additional storage, higher capacities in wind and solar PV are deployed to charge the storage for use at a later time. This explains the large difference in cumulative energy cost savings between the w/ Tx and w/o Tx branches.

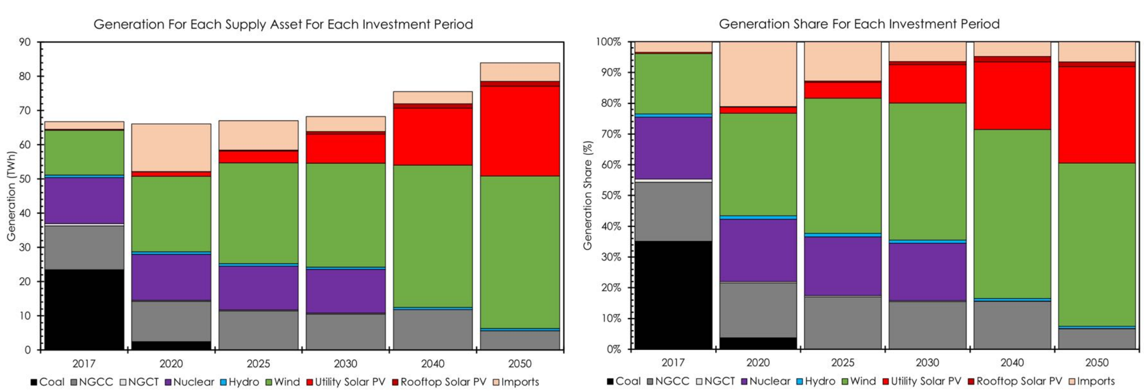


Figure 37: The electricity generation share by investment period in TWh (left) and percentage (right) for Minnesota. Comparing these panels to those in Figure 31 illustrates the differences in the share of electricity generated in Minnesota. By 2050, in this scenario, over 50% of the electricity comes from wind, while 30% comes from solar PV. This is 23% more generation from wind and solar compared with the Baseline scenario. Only 6% comes from natural gas, compared with 38% in the Baseline scenario. The electricity generated covers more sector demands than in the Baseline scenario.

In Figure 37 the Minnesota electricity generation shares for each investment period are shown. The figure demonstrates that decarbonization moves generation away from fossil-fuels to variable generation (wind and solar PV). Further, the electrification alters the demand requirements, which further supports variable generations; since the new load profiles are more flexible. There was 23% more variable generation in this scenario compared with the Baseline. Storage is dispatched more frequently in this scenario and imports are larger than in the Baseline (for the w/ Tx branch).

The process of electrification altered the input demand profiles for Minnesota. These are processed within WIS:dom and it can decide to utilize the flexibility of these new loads; but must pay a cost to do so. Figures 38 and 39 display January and July dispatch stacks for Minnesota. They show how Minnesota could electrify and decarbonize on a high-temporal frequency. It becomes clear that the system shown in Figures 38 and 39 are fundamentally different to the one shown in Figures 32 and 33.

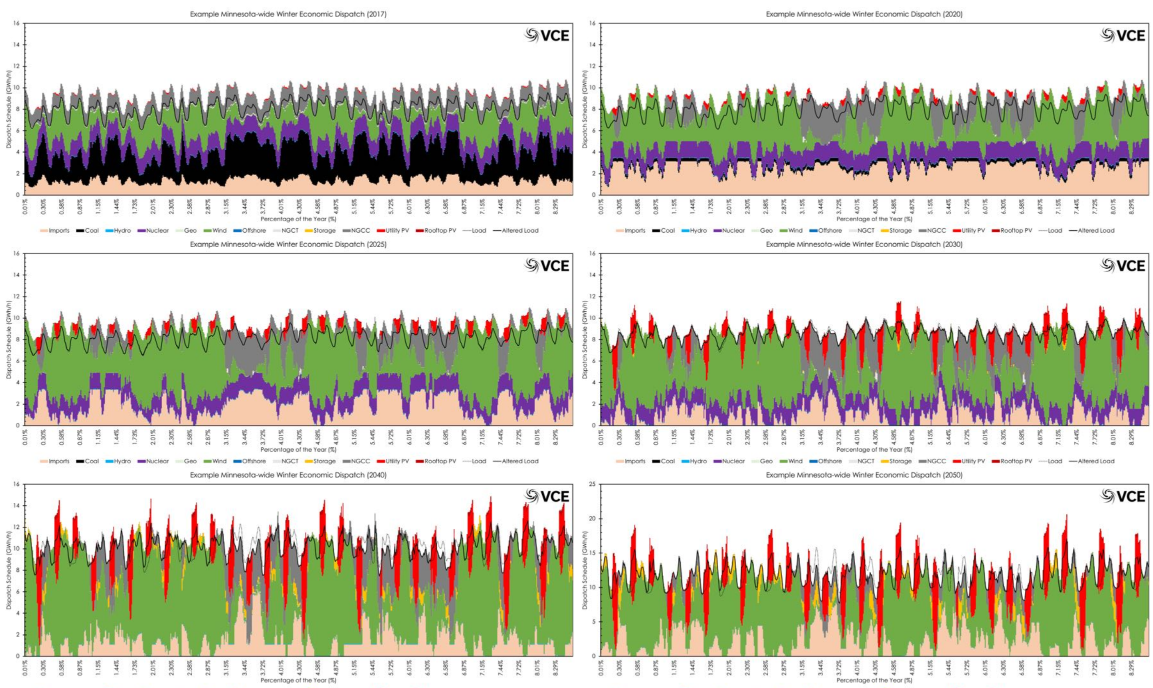


Figure 38: The economic dispatch over the month of January for Minnesota for each of the investment period. WIS:dom finds combinations of generation and demand-side resources for each 5-minute interval for all of Minnesota to keep electricity flowing throughout each investment period. There is more time-periods with flexibility being dispatched by WIS:dom, along with storage, variable generation and imports.

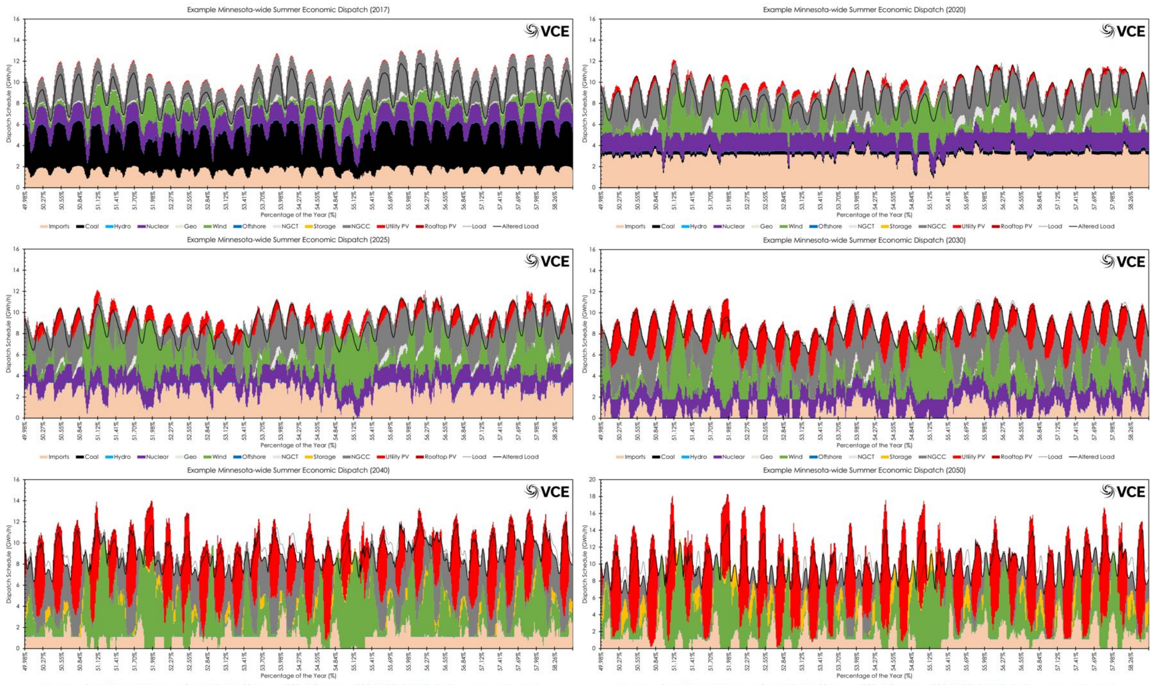


Figure 39: The economic dispatch over the month of July for Minnesota for each of the investment period. WIS:dom finds combinations of generation and demand-side resources for each 5-minute interval for all of Minnesota to keep electricity flowing throughout each investment period. The summer months by 2050 have lower peak demand than winter for Minnesota.

Figures 38 and 39 demonstrate that WIS:dom can combine generation, transmission and demand-side resources to provide electricity at high-temporal resolution for Minnesota without fail. There are time periods where it is clear that WIS:dom is dispatching demand-side resources. Compare the solid-black line with the dash-black line. These allow the demand to be more flexible to the changing variable generation. It can be observed that there are many instances of 100% variable generation contributing to the power of the grid. Some of that electricity is stored or transmitted to other regions. The combination of storage and transmission accommodates much higher volumes of variable generation. Inspecting Figures 38 and 39, it can be seen solar PV installations increase along with storage capacity increases.

The addition of demand-side resources enables further accommodation and reduces the burden of the system to seek out more generation sources. Some sources of demand-side flexibility are simple; such as EV charging, which is already available in the mass-markets. The WIS:dom optimization model must pay for the charging to be more flexible. Therefore, there are incentives for customers to act. Note that for EVs, the flexibility is only supplied by delaying or bringing forward the charging time, it is not supplied by vehicle-to-grid discharge of EV batteries. Thus, customers could benefit from payment (or credit to utility bill) for moving their charging, which might be a lower-cost time period. Therefore, customers could "save" twice.

In general, the Minnesota deep decarbonization scenario was more readily feasible to solve than the Baseline scenario. There were more components to the electricity system that could work together and were (anti-)correlated with weather that provides the majority of the fuel for the electricity generation. The dispatch portion involved less computation as the model included more variable generation, since there are fewer unit commitment issues and less competition for fuel. Superimposed on these easier aspects was the ability of the demand to provide dispatch that could avoid extreme periods at lower-cost and complexity than additional generation / transmission resources would have been.

The Minnesota deep decarbonization would require a fundamentally different electricity system in Minnesota than existed in 2017. These changes might prove difficult, but there are high amounts of monetary savings to be exploited if the changes are implemented for Minnesotans. The changes would also reduce the exposure to higher gasoline and natural gas prices in the future.

c. High natural gas costs

The high natural gas scenario is designed to evaluate the impact of higher natural gas prices on the Baseline and MN deep decarbonization pathways. The Annual Energy Outlook (AEO) high natural gas price is used as the new input. With the higher natural gas price, WIS:dom must determine the least-cost pathways to meet the goals set in the Baseline and MN deep decarbonization scenarios.

The higher natural gas prices have relatively low impact on the MN deep decarbonization scenario. In fact, the transition follows a relatively similar pathway. It does denude, slightly, the energy savings for Minnesota. In Figure 40, the cumulative savings by 2050 reach \$45.2 billion (\$1,076 average annual household saving), a reduction from the MN deep decarbonization scenario of \$6.2 billion (\$89 reduction in the average annual household saving). For the higher natural gas cost baseline scenario, the exposure to the higher natural gas prices is much higher than in the MN deep decarbonization scenario. In fact, it increases the cumulative costs for energy by 2050 by \$15.6 billion (or \$294 annually per household). The additional spending comes from higher fuel costs and more capacity of generation, which results in emissions falling by a further 9% compared with the Baseline by 2050.

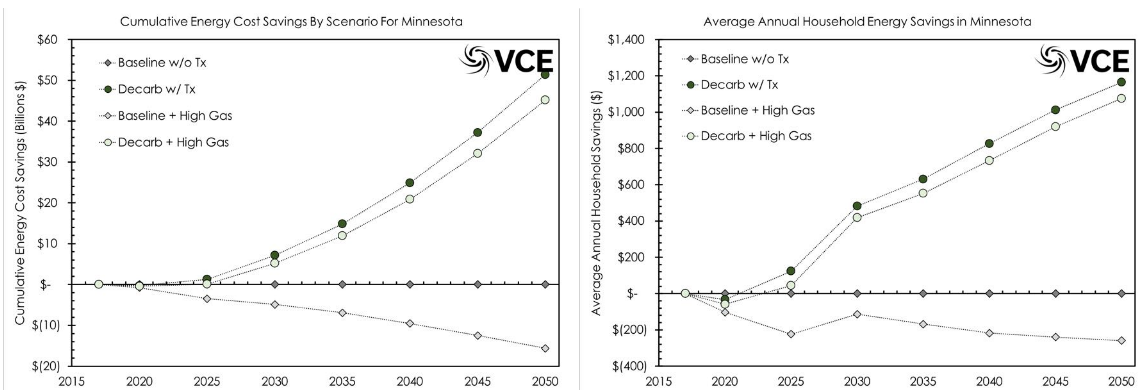
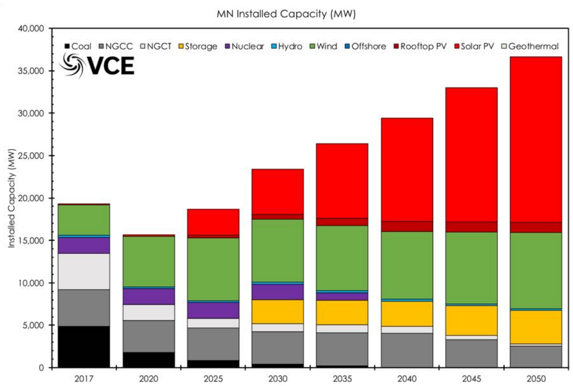


Figure 40: The cumulative (left) and average annual household energy (right) savings or increases for the higher natural gas price scenario. The exposure to increased natural gas prices is much higher for the Baseline than in the MN deep decarbonization scenario. The higher natural gas prices did drive more investment into wind and solar PV power, which reduces emissions by a further 9% in the Baseline scenario.

The higher natural gas price scenario has illustrated that under the electrification and decarbonization pathway there is less exposure to the volatility of natural gas fuel costs. The lower exposure comes from two areas: 1) less natural gas needed for heating; and 2) less natural gas required within the electricity sector to produce power. Another feature of the higher natural gas price scenario within the Baseline scenario was that WIS:dom constructed more wind and solar compared with the lower natural gas price. This suggests that building more natural gas power plants could come with unnecessary risks of fuel prices exceeding forecasts; while, in contrast, variable generation is not exposed to that risk. In fact, as shown in Figure 41, the natural gas power plant capacity in Minnesota is halved in the high natural gas scenario compared with the Baseline (see Figure 30). With the change in capacity comes more full-time employment, which is another positive attribute to the variable generation installations.



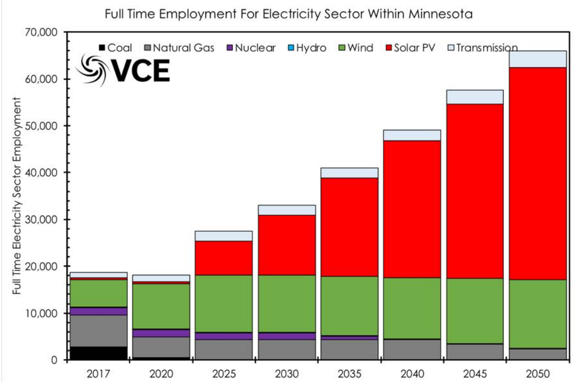


Figure 41: The installed capacity (left) and full-time jobs (right) for the high natural gas baseline branch. With higher natural gas prices, the baseline scenario installs half the amount of natural gas and replaces it with wind and solar PV power. With the additional capacity comes more full-time employment. Compare these panels to those in Figure 30.

d. Zero emission decarbonization for Minnesota

This scenario is similar to the MN deep decarbonization scenario, but with the additional constraint of completely removing emissions from the electricity sector by 2050 (rather than the 91% reduction from 2005 levels). The scenario has two branches that address the differences created by allowing or restricting interstate transmission capacity expansion.

The impact of aiming for 100% reduction in emissions for the electricity sector is a reduction in energy cost savings. These reductions in savings are amplified if interstate transmission expansion is restricted. The cumulative savings for this scenario, w/ Tx, is $44.9 billion ($6.9 lower than the MN deep decarbonization scenario); however, the cumulative savings are reduced by $35.5 billion to $15.9 billion when interstate transmission is restricted. The dramatic reduction is caused by the lack of geographic diversity when interstate transmission cannot be expanded. It even causes the household savings to become additional annual costs by 2050 amounting to $191 per household. Figure 42 shows these values for each investment period.

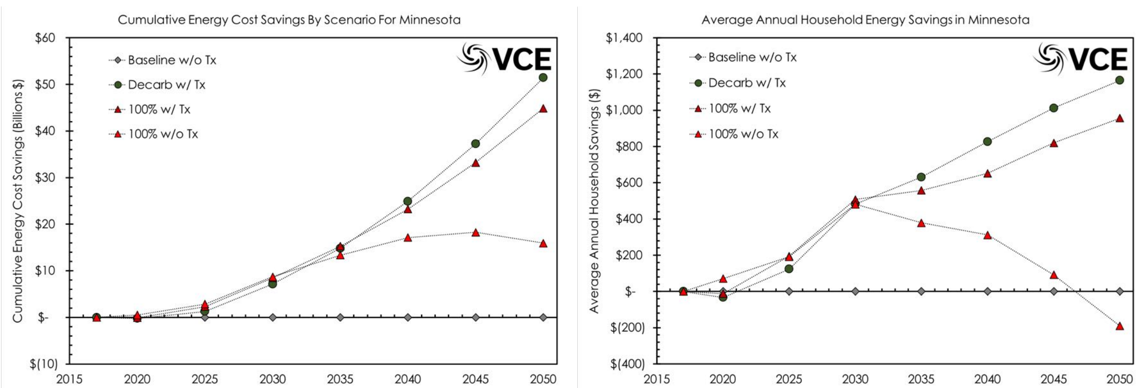


Figure 42: The cumulative savings compared to the Baseline scenario (left) and average annual household saving (right) for the zero-emission electricity grid scenario. Unit 2030 the branches look incredibly similar, but after that time the costs to provide reliable power diverge.

The difference in cost is quite remarkable. The increase between the branches is primarily due to the geographic diversity in Minnesota being saturated and without increased transmission to other regions, more storage and capacity is required. Figure 43 shows the installed capacities in Minnesota for the two branches. It highlights the need for storage in a transmission constrained situation and how smaller regions can be impacted by weather variability.

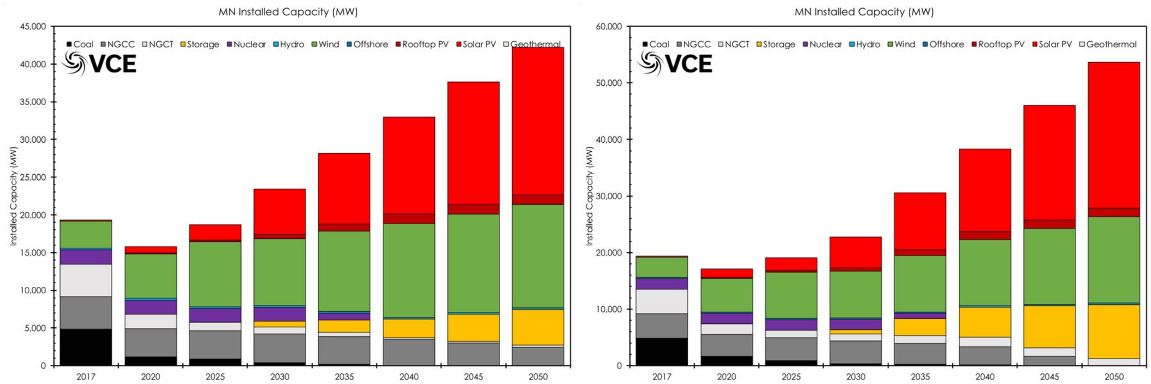


Figure 43: The installed capacity for the w/ Tx branch (left) and w/o Tx branch (right). Minnesota can still have natural gas generation for the w/ Tx because it provides electricity to other parts of MISO, when it is short of power, in exchange for zero-emission electricity at other times when Minnesota is short of power. For the w/o Tx branch, the Minnesotan electricity grid must balance everything on its own. To do this WIS:dom deploys much more storage along with wind and solar PV. The total capacity is 15,000 MW higher in the w/o Tx branch compared with w/ Tx branch.

Along with higher power capacity of storage, there is a substantial increase in the energy storage capabilities in Minnesota to cover the variability of the weather over its footprint. Figure 20 highlights the scale at which the 100% w/o Tx branch is in terms of storage capacity. There is over 165,000 MWh of energy storage capacity deployed. That provides over seventeen hours of storage discharge at full power (~9,500 MW). The full discharge capability covers over half of the peak demand for Minnesota.

The WIS:dom optimization model can still dispatch the system without fail for all 5-minute intervals for each of the investment periods when there are no emissions from the electricity grid allowed within Minnesota. In Figure 43, natural gas combustion turbines are still present, which provide capacity to ensure that if there are extreme, unexpected, events dispatch capabilities are present. The natural gas combustion turbines are not used for any 5-minute period in 2050, but rather provide capacity, just in case. Figure 44 shows the dispatch of the Minnesota footprint for the 100% w/o Tx branch in 2050. It depicts a future where more flexibility is used, more storage is deployed, and high capacities of wind and solar provide all the electricity requirements. There are imports and exports along existing interstate transmission corridors.

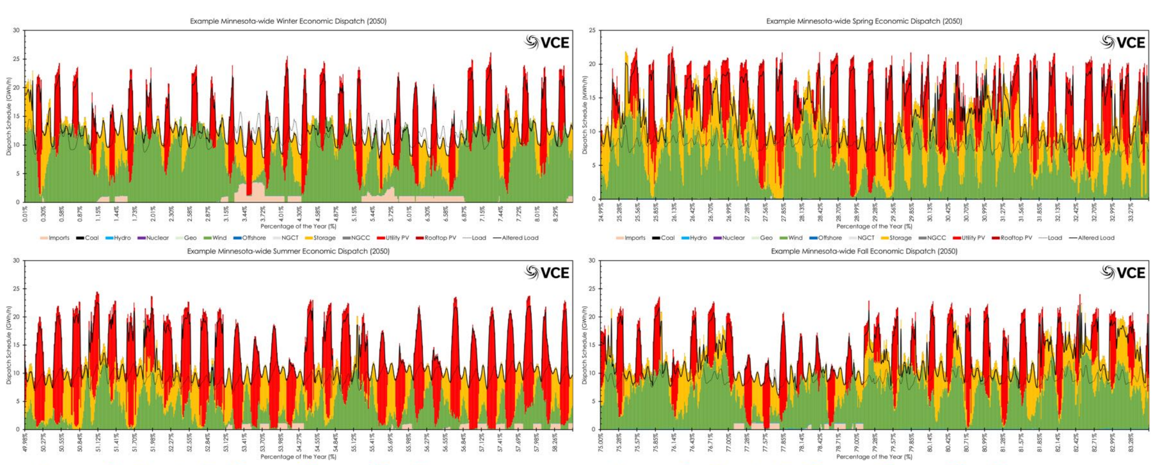


Figure 44: Example monthly dispatch stacks and load curves for Minnesota in 2050 for the 100% w/o Tx branch (completely decarbonized electricity grid by 2050). Top-left represents Winter (January), top-right Spring (April), bottom-left Summer (July), bottom-right Fall (October). WIS:dom performs the dispatch for all parts of the Eastern Interconnection for each 5-minute interval for the investment period. Notice that the load is considerably altered by storage and demand-side resources. Lower generation availability is covered by demand-side resources, storage discharge, and limited imports.

Figure 44 illustrates the different paradigm required to fill all electricity requirements with resources from within Minnesota. It is clear from the figure that storage and demand-side resources provide the flexibility to accommodate the variable resources.

The zero-emission electricity grid in Minnesota reduces economy-wide emissions by a further 3% from 2005 levels when compared with the MN deep decarbonization scenario. The cumulative energy cost increased beyond the MN deep decarbonization scenario by between $6.9 billion to $35.5 billion for that extra 3%. The additional spending may be required to meet climate mitigation requirements, but this scenario suggests there may need to be other avenues available to remove these final emissions. It should be mentioned that, in this scenario CCS was not deployed because there are still some emissions from combustion of natural gas (or coal) so cannot achieve zero-emissions with Minnesota alone, and for the w/ Tx branch the natural gas provided power for other regions in exchange for zero-emission power at other times; hence the CCS component was not chosen.

e. Eastern Interconnection decarbonizes with Minnesota

This scenario analyzes the impact to Minnesota if the whole Eastern Interconnection electrifies and decarbonizes to meet the 80% reduction (from 2005 levels) in economy-wide emissions by 2050. To execute this scenario, the other sectors for each state in the Eastern Interconnection had to be estimated and the electrification potential was assessed. WIS:dom, again, was provided input load profiles for each 5-minute interval for each investment period. The flexibility available through the electrification was computed and differentiated for each state, depending on their demand mix.

When the entire Eastern Interconnect decarbonizes along with Minnesota there is more competition for certain types of resources. The competition between entities within the Eastern Interconnection changes how Minnesota can evolve to meet the goal of *80x50*. Due to this competition the cumulative energy savings are reduced compared with the MN deep decarbonization scenario. The cumulative savings are reduced to $41 billion by 2050 (a reduction of $10.4 billion compared with the MN deep decarbonization scenario), which results in the average annual household saving being $954 by 2050 ($211 lower). This reduction in savings is meaningful, but it should be noted that Minnesotans are still saving substantially on their energy bills compared with the Baseline scenario. Figure 45 shows the savings by investment period.

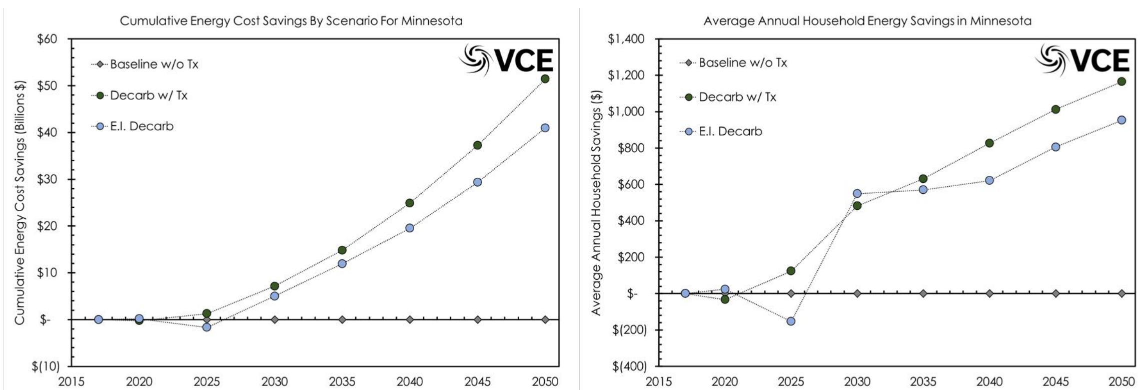


Figure 45: The cumulative (left) and average annual household energy (right) savings or increases for the EI decarbonization scenario. The simultaneous electrification and decarbonization of the Eastern Interconnection creates competition for certain resource types. This alters Minnesota's pathway to reach its *80x50* target.

This is the only scenario where the entire Eastern Interconnection is substantially altered compared with the Baseline scenario. The siting of generation is completely altered by the *80x50* target, since a transition to natural gas alone will not meet the emission reductions required. Figure 46 displays the siting that WIS:dom selects for this scenario. If compared with Figure 28 there are some striking differences. First, there are far fewer natural gas power plants. Secondly, there is higher amounts of wind and solar PV installations; in particular there is offshore wind on the East Coast. Thirdly, there is a resurgence of nuclear power to be able to meet the emission reduction targets at least-cost. Finally, there is a dramatic increase in rooftop solar PV, which is a reflection on the siting constraints in WIS:dom for utility-scale generation in protected regions. To achieve the emission reductions required, WIS:dom needs to install zero-emission technologies near load centers to help with peak demand, these sites are more suitable for rooftop solar PV.

Interestingly, Figure 46 does not appear to include much larger interstate transmission corridors. This is explained by the electrification component. Electrification provides flexibility, but also changes the seasonal profile of demand, which (with the energy efficiency) reduces the peak power needs. These two aspects of electrification actually reduce the burden on the transmission system.

The installed capacity across the Eastern Interconnection is shown in Figure 47. It highlights the dramatic differences between this scenario and the Baseline one. There is much less natural gas and higher capacities of variable generation. It also demonstrates the need of nuclear power for deep decarbonization under a resource constrained environment. For the same reason, Figure 47 depicts the installation of offshore wind in large quantities to help support decarbonization of the East Coast states.

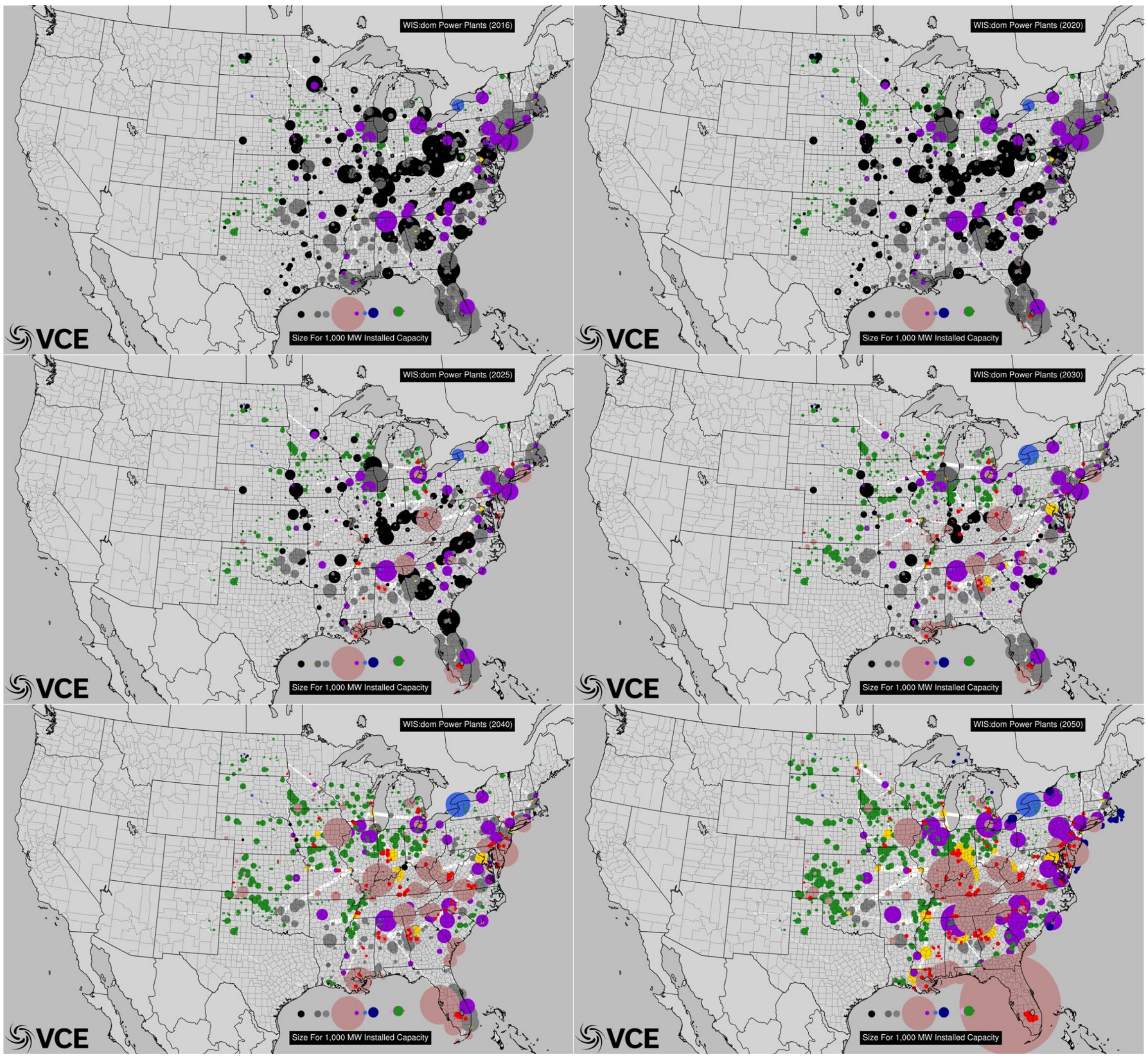


Figure 46: The geographic siting of generation created by WIS:dom for the Eastern Interconnection Decarbonization scenario. The investment periods can be followed from 2017 in the top-left panel to 2050 in the bottom-right panel. The white lines represent the interstate transmission capacity. The thicker the lines the greater the capacity. The colors are (in order shown at bottom): black = coal, yellow = storage, dark grey = NGCC, light grey = NGCT, rose red = rooftop solar PV, purple = nuclear, light blue = hydroelectric, dark blue = offshore wind, pink = geothermal, green = onshore wind, red = solar PV.

Figure 47 further highlights the diversity of the Eastern Interconnection and shows that some states have a more difficult process to decarbonize completely. Some of the states in the Eastern Interconnection consist entirely of variable generation and storage, while others are exclusively zero-emission generation, and a third category of states have natural gas supplementing the variable generation. Figure 48 aggregates together the information in Figure 47 for the entire Eastern Interconnection. The figure suggests that there are the resources available to electrify and decarbonize the Eastern Interconnection. Compared with Baseline the peak demand is much higher than synchronous generation, and this is supported by the demand-side resources and the storage being deployed (along with transmission links). Of course, the total capacity in the Eastern Interconnection is higher than in the Baseline. Figure 48 also shows the installed capacity in Minnesota. It suggests that if the Eastern Interconnect also electrifies and decarbonizes that the electricity grid would benefit from being more wind dominant. It also shows nuclear power existing in Minnesota through 2050.

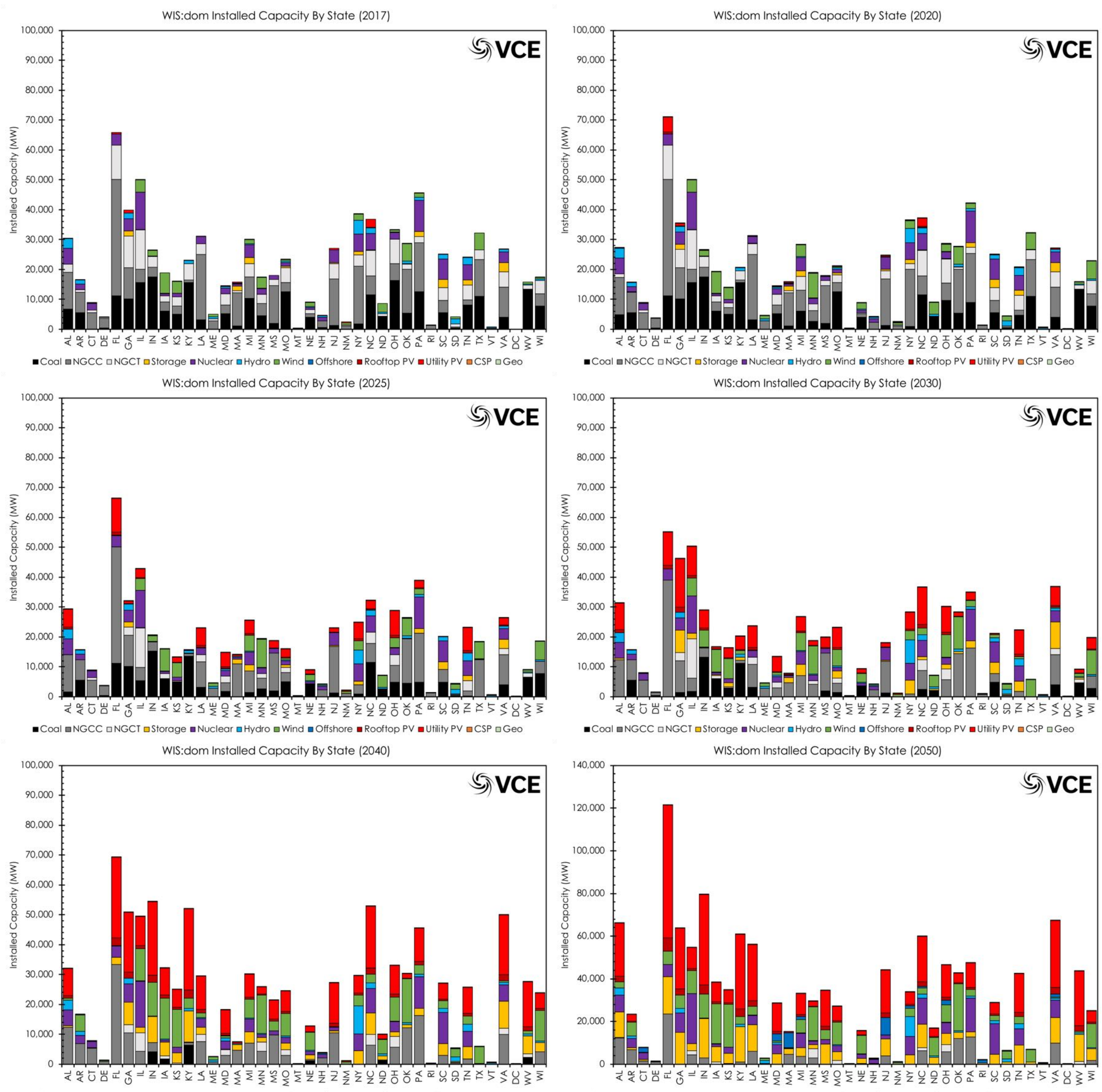


Figure 47: The installed capacity for each state in the Eastern Interconnection for each investment period optimized by the WIS:dom model. The evolution of the electricity grid can be followed from the top-left (2017) to the bottom-right (2050). The system in 2050 for this scenario is dominated by wind, solar, nuclear and storage.

Even with the Eastern Interconnection altering the scale and distribution of generation substantially, WIS:dom must still provide robust dispatch for each 5-minute interval for all of the investment periods across the EI. The dispatch for winter and summer time periods are shown in Figures 49 and 50. The power dispatch and flexibility are completely different to the Baseline, but power is provided without fail for all 5-minute intervals in all regions. The portfolio of resources can balance all the requirements across the Eastern Interconnection, while minimizing the system costs. It should be noted that the power connections between Mexico, Canada and the US are not expanded in this scenario.

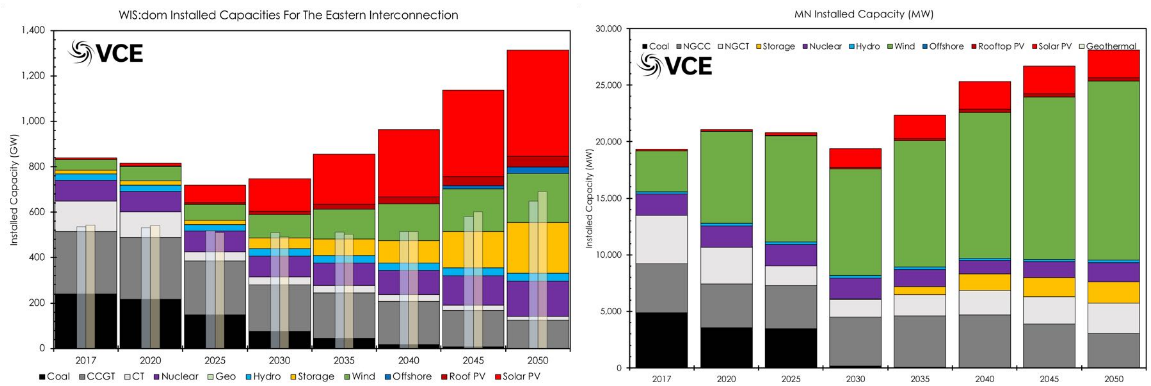


Figure 48: The installed capacity across the Eastern Interconnection (left) and Minnesota (right) for the Eastern Interconnection decarbonization scenario. More nuclear is in this pathway compared to others. Minnesota is wind dominated, since it has better wind resources and solar PV resources are allocated by WIS:dom to better resource regions in the EI.

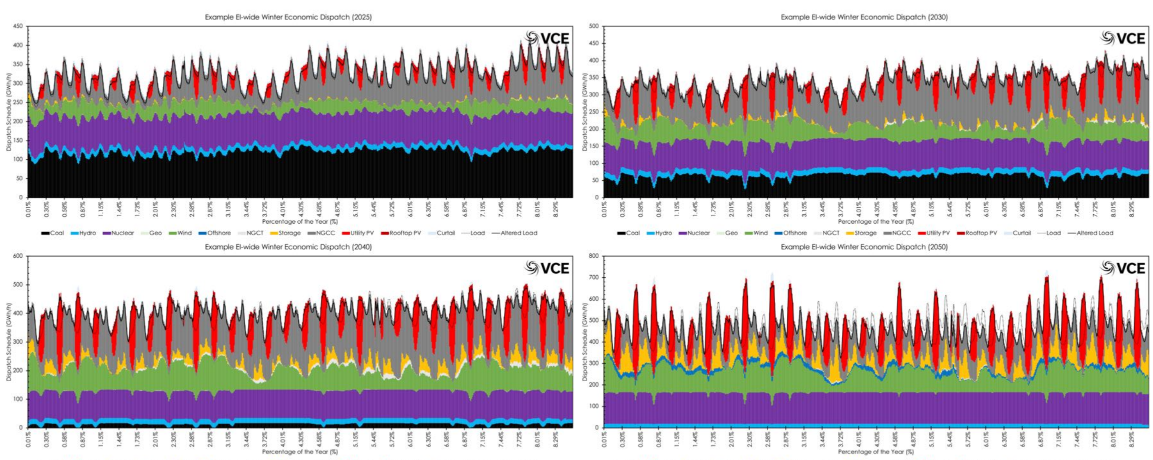


Figure 49: The economic dispatch over the month of January for the Eastern Interconnection. The investment periods of 2017 and 2020 are not shown as they are similar to those in the Baseline scenario.

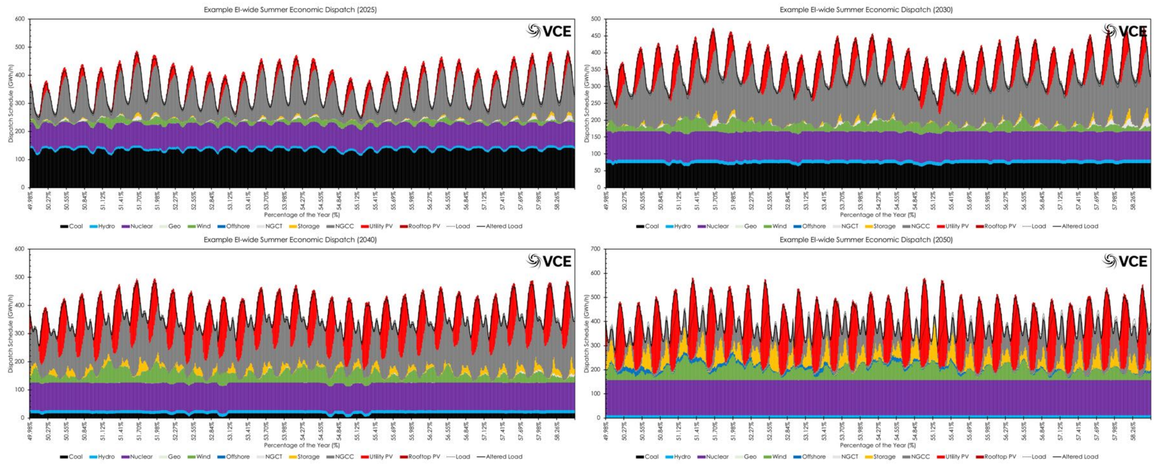


Figure 50: The economic dispatch over the month of July for the Eastern Interconnection. The investment periods of 2017 and 2020 are not shown as they are similar to those in the Baseline scenario. It can be observed that the combination of generation and demand-side flexibility can accommodate large amounts of variable generation.

With the altered dispatch and siting across the Eastern Interconnection, the generation shares are changed compared with the Baseline scenario. Figure 51 displays the generation shares for the Eastern Interconnection. It shows an electricity system dominated by clean resources. Approximately 60% of the generation comes from wind and solar, while 30% comes from nuclear and 10% from natural gas.

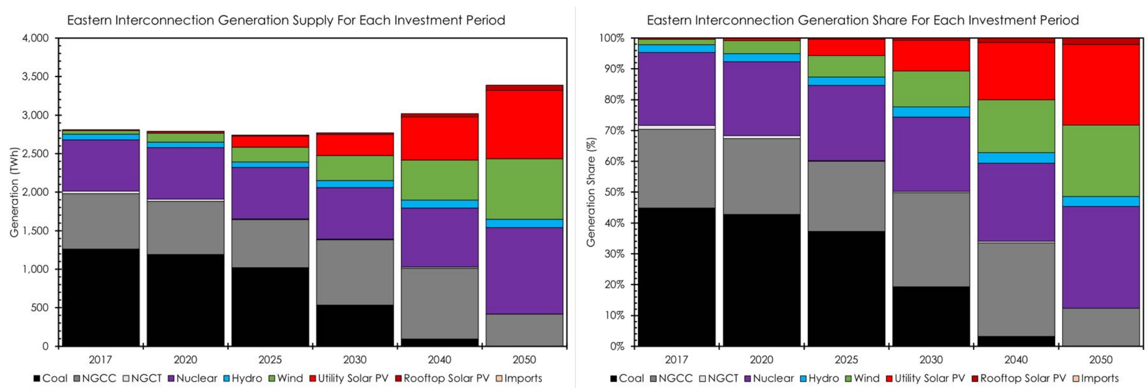


Figure 51: The generation share for the Eastern Interconnection for investment periods. Due to resource scarcity (MW buildout), WIS:dom expands the nuclear capacity across the Eastern Interconnection to provide clean generation in support of the variable generation with storage.

With the Eastern Interconnection decarbonizing alongside Minnesota there comes cost increases, as shown in Figure 45. However, if the EI doesn't decarbonize with Minnesota the emission reductions are much smaller. Therefore, the additional spend felt by Minnesotans is rewarded by much more dramatic emission reductions helping mitigate climate change. Figure 52 displays the carbon dioxide emissions for each state. Compared with the values in Figure 32, it can be computed that cumulative emissions from the electricity sector are reduced by 12,736 million metric tons. Further, the emissions from outside the electricity sector are also reduced dramatically. In total, the Eastern Interconnection emitted 20% the emissions that it did in 2005 under this scenario pathway.

The lower emissions in the rest of the Eastern Interconnection helps Minnesota integrate with the wider grid while decarbonizing, which allows the deployment of lower-cost generation more suited to the Minnesota climate. Nevertheless, this increases costs for Minnesota compared with the Eastern Interconnection being Baseline. Even with the added constraint of resource competition, Minnesota achieves its target of *80x50* with energy costs much lower than 2017. The costs could potentially be even lower, because as the Eastern Interconnection electrifies and decarbonizes the cost of natural gas would likely fall due to substantial demand reductions. The annual economy-wide emissions are lower than 750 million metric tons by 2050.

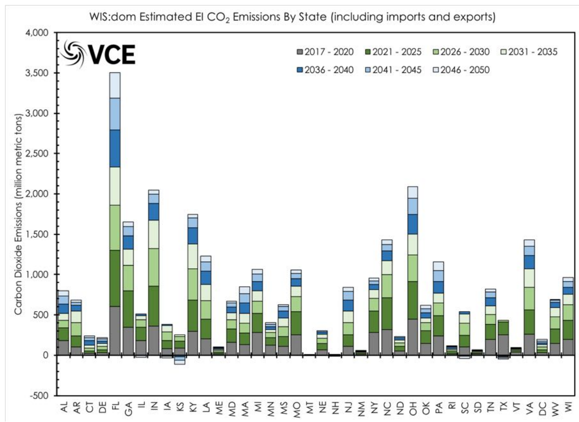


Figure 52: The electricity sector emissions by state for all the investment periods. The electricity sector cumulatively emits 12,736 million metric tons less than in the MN deep decarbonization scenario. These emission reductions are amplified by the reduced emissions from all other sectors via the electrification. The annual economy-wide emissions for the Eastern Interconnection is below 750 million metric tons by 2050.

f. Minnesota deep decarbonization with dominant DERs

This scenario analyzes the impact of Minnesota achieving the *80x50* target using a different set of tools to those in the MN deep decarbonization scenario. It is assumed that additional energy efficiency can be achieved that results in electric demand being 10% lower than the MN deep decarbonization scenario for each investment period after 2020. It is further assumed that the level of flexibility from demand-side resources is increased by approximately 50%.

This scenario changes the focus of the electrification and decarbonization to more localized and distributed technologies. Figure 53 shows that the energy cost savings for Minnesotan's are similar to those in the MN deep decarbonization scenario, albeit slightly lower. It should be noted that the additional 10% energy efficiency is provided at no cost to the system in WIS:dom. The cumulative saving reduction is $1.4 billion compared with the MN deep decarbonization scenario and the average annual energy cost saving is reduced by $18 by 2050.

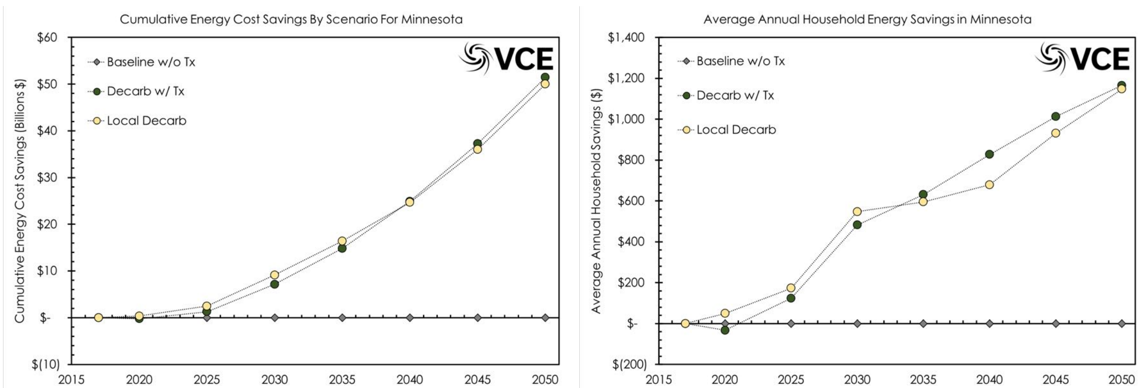


Figure 53: The cumulative (left) and average annual household (right) energy savings for Minnesotans. The local decarbonization results in similar savings as the MN deep decarbonization scenario.

From a generation perspective, WIS:dom replaces much of the utility-scale solar PV in Minnesota with rooftop solar PV. The additional rooftop solar reduces the burden on the transmission buildout within the state, but the resulting dispatch is relatively similar. This is because the generation aggregated over the state appears similar. Due the generation being closer to load centers, the amount of wind and other generation sources are changed slightly. Overall, the major change is related to solar PV deployments and transmission investments. WIS:dom still exchanges power with MISO because of the over-generation at the solar peak, which is partly absorbed by demand-side resources and storage, but requires an interconnected grid to balance efficiently. The installed capacities are shown in Figure 54.

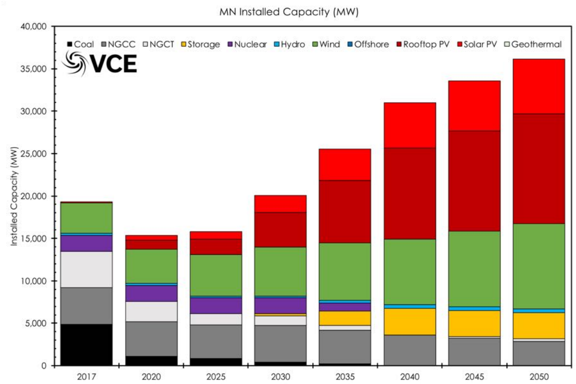


Figure 54: The installed capacity in Minnesota. The rooftop solar PV substitutes the utility-scale PV, and because of its lower generation potential requires higher capacities to replace it.

Other than the substitution of utility-scale solar PV with rooftop solar PV, much of the system performs as it did in the MN deep decarbonization scenario. With rooftop solar PV comes added peak load reduction due to thermal heat gain reductions and a diminishment of some transmission losses. Further the energy efficiency reduces the capacity requirements. These differences combined create a pathway that achieves the 80% reduction by 2050, using a different mixture of technologies.

g. Minnesota deep decarbonization with less flexibility

This scenario is designed to determine how Minnesota could achieve the *80x50* target if the new loads that come from electrification have much lower flexibility capabilities than assumed in the MN deep decarbonization scenario. It is assumed that the flexibility is one quarter of that estimated in the MN deep decarbonization scenario.

The reduced flexibility means that the new loads become more inelastic and cannot respond to price signals to alter the demand as easily. WIS:dom finds adequate solutions at least-cost with the lower flexibility numbers. Moreover, there are few changes to the composition of the pathway. The most notable changes are more utility-scale PV and storage. This pairing compensates for the reduced flexibility. These additional resources reduce the energy cost savings (that are calculated by comparing each scenario with the Baseline scenario) by a cumulative $2.4 billion by 2050, thereby reducing the average annual household saving by $51 by 2050 as depicted in Figure 55.

In Figure 56, the dispatch stacks for 2050 are shown for a representative month for each season. Comparing the panels in Figure 56 with Figures 38 and 39 (the bottom-right panels) for winter and summer, respectively, it can be seen that the lower flexibility is completely substituted with solar PV generation and storage dispatch. In fact, the storage technologies are dispatched twice as much with the reduction of flexibility.

The change in the flexibility of the demand-side resources does not alter the emissions reduction profiles and does not adversely impact the system being provided power for each 5-minute interval for all investment periods without fail.

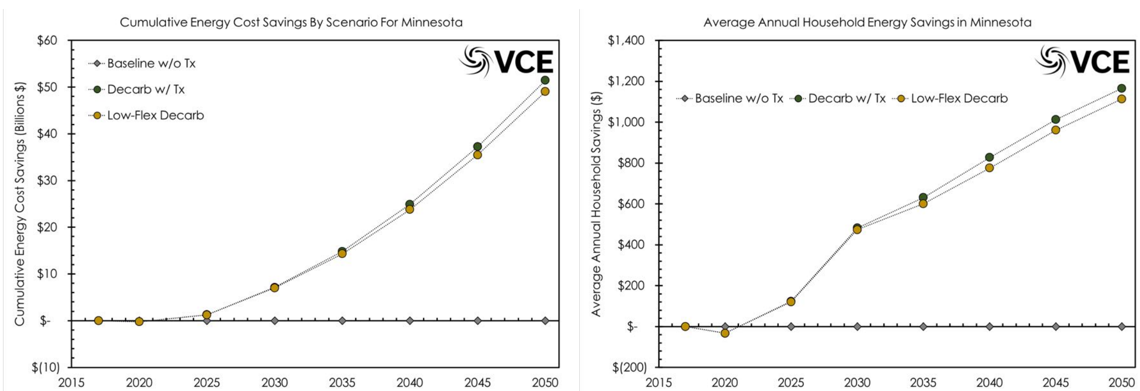


Figure 55: The cumulative (left) and average annual household (right) energy savings for Minnesota. This scenario traces the MN deep decarbonization scenario closely. The additional spending is to provide more utility-scale generation and storage to compensate for the lower flexibility levels.

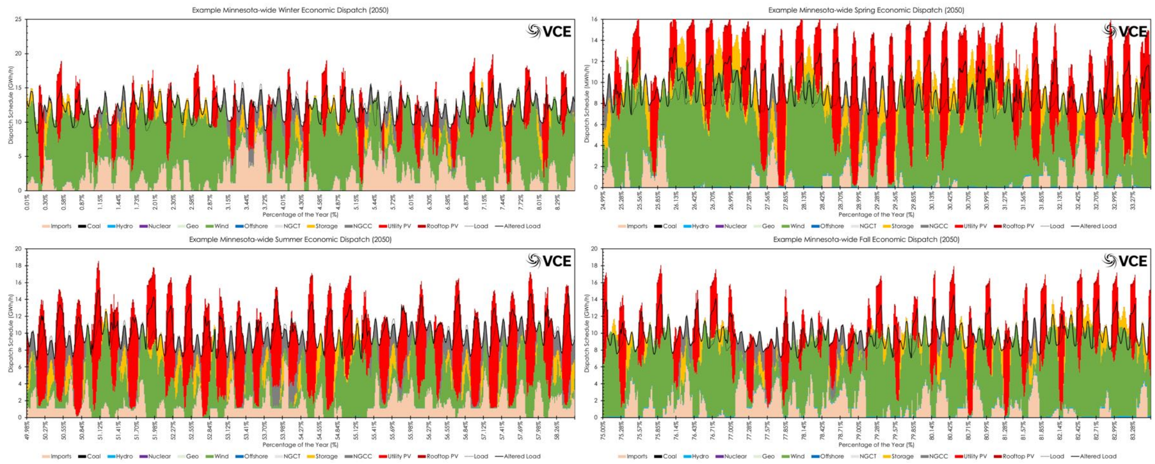


Figure 56: Representative dispatch and load stacks for a month of each season. Compare the winter and summer month panels with those in Figures 38 and 39 for 2050. It can be seen that the lower flexibility is almost entirely compensated for by more solar PV and storage dispatch. The dispatch of storage is doubled in this scenario compared with the MN deep decarbonization scenario.

h. Minnesota deep decarbonization nuclear sensitivity

This scenario assessed the impact to the Minnesota deep decarbonization if nuclear was allowed to retire early or relicense through to 2050. Essentially, for the early retirement, the WIS:dom optimization model had the ability to retire the two nuclear power plants in Minnesota before their scheduled relicense dates. The WIS:dom optimization model did not choose to retire the two power plants before the relicense dates, opting rather to retire them as scheduled. Therefore, no differences were created by this branch of the scenario.

For the relicense branch, the WIS:dom optimization model was constrained to relicense the two nuclear power plants in Minnesota through 2050. There are differences in this branch of the scenario. First, the relicense pathway reduces the overall cumulative energy cost savings by $2.4 billion by 2050 compared with the MN deep decarbonization scenario. This translates to lower average annual household energy savings by 2050 by $37 as shown in Figure 57.

The nuclear power plants being kept online through 2050 has a noticeable effect on the installed capacity of variable generation; yet almost no influence on the natural gas power plant capacities. As can be seen in Figure 58, storage installation by 2050 are 1,000 MW lower, wind installations are 2,000 MW lower, and solar PV is 3,000 MW lower. The installed capacity of the nuclear power plants is approximately 1,800 MW. The lower installed capacity reduces the total full-time jobs created by 2050.

The installed capacity is changed, but the emission reductions are similar. The cost of keeping the nuclear power plants online is more expensive that retiring them and building more capacity in variable generation. The EI decarbonization scenario illustrated that more nuclear capacity was necessary in a resource constrained environment. Thus, it seems beneficial to retire the nuclear power plants on schedule and consider expansion if the remainder of the Eastern Interconnection progresses with electrification and decarbonization along with Minnesota (if that is the pathway that occurs). This scenario suggests is that early retirement of these nuclear power plants is also not warranted based on economics.

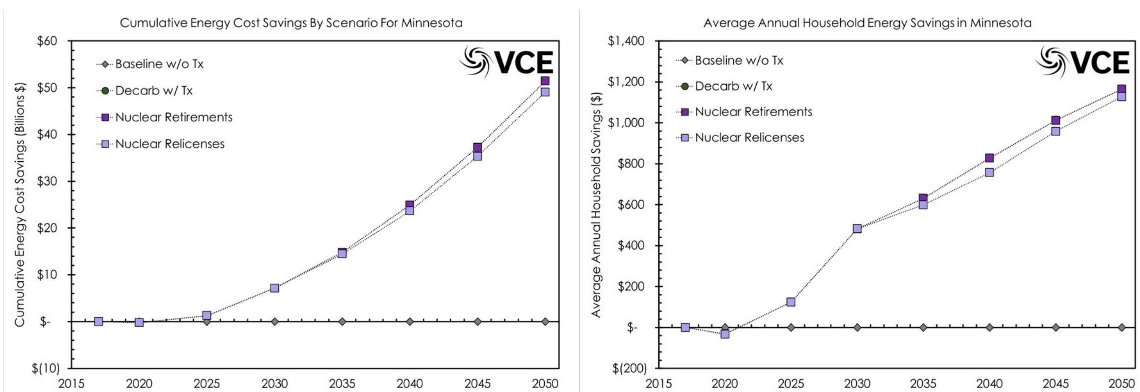


Figure 57: The cumulative (left) and average annual household (right) energy savings for Minnesota. These scenario traces the MN deep decarbonization scenario very closely. In fact, the early retirement of nuclear branch is actually identical. The additional spending in the nuclear relicense branch is to pay for the more expensive nuclear plant than lower-cost variable generation with storage.

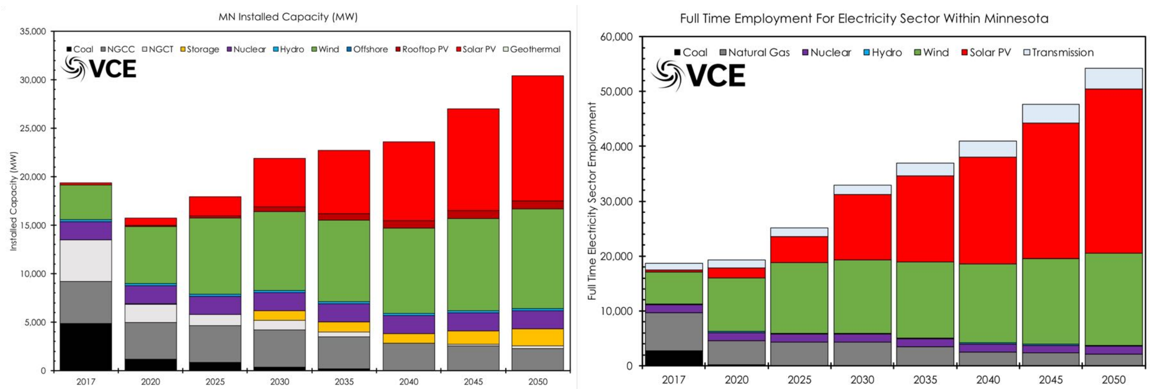


Figure 58: The installed capacity (left) and full-time jobs (right) in Minnesota. The installed capacity is approximately 4,000 MW lower than in the MN deep decarbonization scenario. This is because nuclear (1,800 MW) remains online while 1,000 MW of storage, 2,000MW of wind, and 3,000 MW of solar PV are not built. The lower installed capacity reduces full-time jobs in the electricity sector.

i. Scenario informed recommendations for Minnesota

This sub-section is dedicated to suggestions and recommendations for Minnesota based on the information and data that has been compiled by performing the eight scenarios with thirteen total branches. These are intended to provide the least-risk, learn-by-doing, least-cost activities that Minnesota can do to facilitate the largest array of pathways for the future of the Minnesota electricity grid so that it can achieve the goal of removing 80% of economy-wide emissions (from 2005 levels) by 2050. The suggestions and recommendation are only the opinions of the authors and their perspective of the modeling results.

List of suggestions and recommendations:

- Consider planning the electricity systems within Minnesota with consideration of generation, transmission, storage, EVs, DSM, DR, and the wider Eastern Interconnection impacts included.
- Update the planning frequently, in the order of every year, to capture the changing economics and technologies that can be included in the evolution of the electricity system.
- Encourage electrification of transportation (particularly light-duty vehicles) and new construction with heat pumps for space and water heating. Retrofit old furnaces and water heaters with heat pump alternatives.
- Educate on the value of electrification with respect to emission reductions, load growth potential, and the added flexibility it can bring.
- Retire the coal-fired power plants in Minnesota as rapidly as possible. No coal-fired power plants are necessary after 2030.
- Keep the Monticello and Prairie Island nuclear power plants online until their scheduled relicense dates, at which point retire them.
- Only replace natural gas power plants (both combined cycle and combustion turbines) that are due to retire with equal capacity. Do not add new net capacity for these technologies in Minnesota. They run the risk of becoming stranded due to reducing cost renewables and exposure to possible fluctuating fuel prices.
- Build, at least, another 2,000 MW of wind by 2025, and target 10,000 MW by 2050.
- Make accommodations and install at least 2,000 MW of rooftop solar by 2050, there should be 1,000 MW installed by 2030.
- Have over 2,000 MW of utility-scale solar PV by 2030 within Minnesota. Aim to construct 10,000 MW by 2050.
- Connect 1,000 MW of electric storage by 2030. The duration of this storage can be short (<15 minutes). By 2050 have 2,000 MW of storage in Minnesota with an average of 5 hours of energy capacity.
- Expect installed capacity in Minnesota to increase by approximately double by 2050 if electrification has taken place to enable the decarbonization with variable generation.
- Consider wider regional interconnection with MISO, through more interstate transmission to access other geographies for variable resources more frequently.
- Provide guidance to other states on the approaches and methods adopted that are successful and ones that are not.

VI. The WIS:dom Optimization Model

The ***WIS:dom*** (***W****eather-****I****nformed* ***S****ystems****:*** ***d****esign,* ***o****peration,* ***m****arkets*) optimization model is the flagship, state-of-the-science, software product created by VCE. A precursor to WIS:dom was the seminal C-OEM (the Co-Optimized Energy Model), which was the first commercial model to be able to co-optimize variable generation, conventional generation, transmission, storage and power flow at a granularity of 13-km and 60-minute for the entire continental United States for a full year, while performing a resource planning for the electricity system from 2015 to 2050. See the link in the footnote[23] for the report produced as part of a planning study performed by VCE for MISO in 2015, using C-OEM.

The WIS:dom optimization model contains numerous improvements and upgrades beyond C-OEM; including its description of generators (and their attributes), weather datasets for variable renewable energy (VRE) [now utilizing 3-km, 5-minute gridded data[24]], transmission lines and power flow, investment time periods, retirements, pollutant tracking, hourly (or 5-minutely) dispatch, reserve requirements, emission constraints, employment and revenue output/input, and economic inputs/outputs. The WIS:dom optimization model will plan the system in customizable investment time periods [1-, 2-, 5-, 10-year] out to a desired time horizon; typically, 2050. Furthermore, WIS:dom has been designed to work at all geographic scales (particularly in the United States) as well as include a wide range of technologies that are appropriate for numerous studies/analyses. The WIS:dom optimization model divides the US into three main regions: The Eastern Interconnect (EI), Western Interconnect (WECC), and ERCOT (Figure W-1). Offshore wind is also considered as an additional layer, along with regions external to the interconnects.

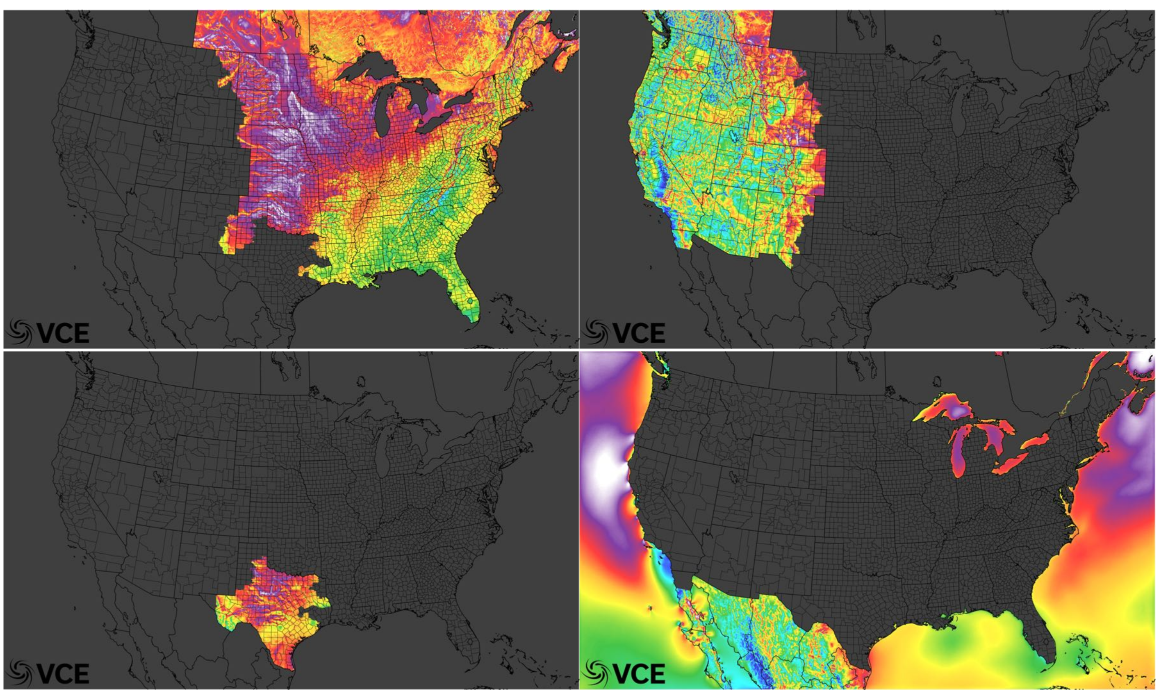


Figure W-1: Illustrating the interconnections that WIS:dom considers in the United States using wind capacity factors from the model's 3-km built-in weather/power datasets.

[23] http://www.vibrantcleanenergy.com/wp-content/uploads/2016/05/VCE_MISO_Study_Report_04252016.pdf
[24] https://www.youtube.com/watch?v=OFPapVWCWk0

The WIS:dom optimization model representation of the electricity grid is then further divided down into the ISO/RTO regions. For example, one that has been utilized extensively is the MISO footprint. The regions can be subdivided further; depending upon the use profile. For example, the WIS:dom optimization model was used for a storage study over the entire MISO footprint (report[25] and presentation[26]).

WIS:dom is the only commercially (or academically) available optimization model that can perform 5-minute (or hourly) chronological economic dispatch for the entire United States footprint, while considering 3-km (or 13-km) resource sites for generation, transmission, storage, and demand-side resources capacity expansion simultaneously. For example, the WIS:dom optimization model can answer the questions of resource adequacy, generation retirement and expansion, dispatch of each generator, pollution tracking, policy drivers, and power flow in the electricity system all in a single scenario.

To make the WIS:dom optimization model practically useful, the model has the ability to read in different data sets for different geographic regions and different study scopes. The consistent modeling framework, while complicated at the outset, allows for simpler transition to new areas of investigation and easier dataset exchange. In the next sub-section, the internal generic assumptions for WIS:dom are described. These include the cost of technologies, retirement treatment, reserves monitored, dispatch characteristics, and initialization grid data.

a. Internal assumptions

The WIS:dom optimization model is designed to solve a capacity expansion and production cost problem for the entire United States. As such, the initialization data, cost assumptions, and demand-side resources are provided for everywhere in that footprint. WIS:dom has the ability to shutdown portions of the domain during its compilation stage via regional identifiers. For this study the Western and the ERCOT interconnections were ignored and flows between those interconnections and the Eastern Interconnect were assumed to be zero. The international transmission lines between Canada, Mexico and the Eastern Interconnection were initialized with their 2017 estimated capacities. The assumed capacity between the EI and Mexico is 0 MW, while the transmission capacity between Canada and the EI is 9,833 MW through six states (Maine, Michigan, Minnesota, New York, North Dakota, and Vermont). To purchase electricity from Canada those states must pay $53.18 per MWh, while exports to Canada provide $40.46 / MWh in revenue. These import and export transmission capacities define the geographic boundary conditions for WIS:dom. No electric power can leak out of this pre-defined system.

The WIS:dom optimization model, as with any modeling software, initializes with data inputs and assumptions. To build the initialization, WIS:dom calculates the location of all the existing generators and transmission lines (greater than or equal to 69 kV). The generator units are aggregated by technology type within each closest 3-km resource grid cell site. The *WIS:dom generator* for a specific technology types (within the 3-km grid resource site) is assigned the weighted average characteristic, per kW or kWh, of all the generation units. These characteristics include heat rates, variable costs to operate, fixed costs, capital costs, age, and power factor. The capacity of the *WIS:dom generator* is the combined capacity of all the units. WIS:dom is initialized in this manner to maximize the utility of the weather datasets that will interact with the generators and provides a uniform grid within which all resources will be sited. The transmission lines are aggregated within the same 3-km grid cells for several voltage bands (69kV and below, 115-138 kV, 230 kV, 345 kV, 500 kV, and 765 kV+). The length of the lines is computed using geodesics between sub-stations within the 3-km grid cells. The capacity of the lines is estimated

[25] http://www.vibrantcleanenergy.com/wp-content/uploads/2017/07/Modernizing_Minnesotas_Grid_LR.pdf
[26] http://www.vibrantcleanenergy.com/wp-content/uploads/2017/07/MN_PUC_July11th_2017_VCE-LR.pdf

using the SIL (Surge Impedance Loading) method with the information about the length of the transmission lines. Figure W-2 displays the SIL estimates by voltage and existing US transmission system. Demand sinks are assumed to be the largest cities in each US county, each being assigned to a 3-km grid cell. Every 3-km grid cell across the US is then processed to determine the transmission capacity available to the nearest demand sink. If no transmission line capacity is found, WIS:dom calculates the distance to the nearest transmission line that does go to the load sink. A cost is assigned for the existing (or interconnection transmission necessary) for each 3-km grid cell. Additionally, an estimated loss function for the transmission to the nearest load sink is determined. It is assumed that electric losses on transmission lines are 3.5% per 100 miles for lower voltages (69kV to 138kV), 2.2% per 100 miles for medium voltages (230 kV to 345 kV) and 1.5% for higher voltages (500kV plus). The distance is the computed for each 3-km grid cell.

Separately, transmission capacity is computed between each of the load centers using the same process of tracing the existing transmission lines. The losses are again estimated from their voltages. Finally, the initialized, reduced form transmission is fixed. In short, WIS:dom estimates costs, electric loss functions, and distances for each 3-km grid cell twice. Once to get resource sites to the zonal load sink and a second time for nodal links between the load sinks. If a resource site is selected in the capacity expansion in WIS:dom, it must pay for the transmission interconnection at that site, and provide power to overcome the electrical losses to transmit the power to the load sink. If the load sinks need to expand capacity between closest neighbors, WIS:dom must pay for that transmission line to be upgraded. If a transmission link does not exist, and one is allowed, WIS:dom must determine if new construction is required, and must pay for that; with costs shared between the two neighboring load sinks.

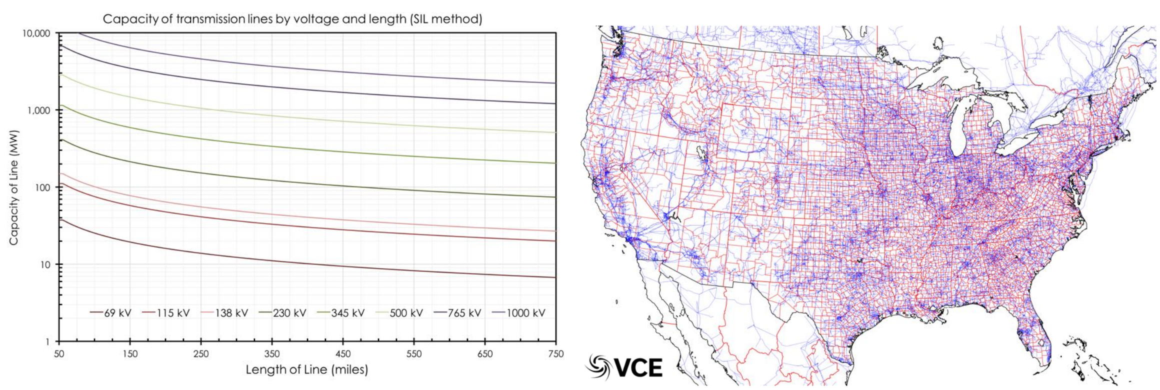


Figure W-2: The typical capacities of transmission lines by voltage as a function of length (left) and the existing transmission system in the United States for all voltages down to as low as 69 kV (right).

The transmission line costs are $1,853.79 per MW-mile for all voltage classes. For HVDC transmission lines the costs are $633.18 per MW-mile of line and $293,760 per MW for the stations. Transmission lines that cross RTO/ISO boundaries pay a penalty of 3x for building or upgrading transmission. There is a similar penalty function for crossing state lines of 1.5x. Figure W-3 displays the initialization of the generators and reduced form transmission for WIS:dom.

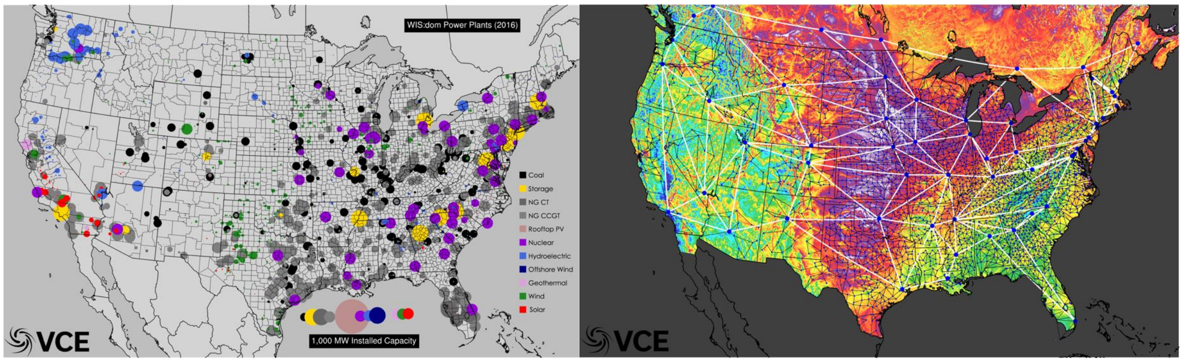


Figure W-3: The initialization of the WIS:dom optimization model; generators (left), reduced form transmission lines (right). The white lines on the right image are interstate transmission aggregation.

For the input data and assumptions, VCE tries to uses publicly available datasets. When public data is not available or incomplete, VCE will create new datasets internally. The publicly available data comes from EIA, FERC, NREL, and other DOE publications. The specific electricity grid data that is provided to WIS:dom includes: Heat rates for thermal generators, minimum loading for thermal generators, fuel costs for thermal generators, fixed O&M costs for all generators, non-fuel variable O&M costs for all generators, remaining capital costs for all generators, transmission topology for all voltages above 69 kV, estimated relicense costs for nuclear generators, repower costs for variable generators, the age and expected life of all existing generators, the power factor of all existing generators, the near-term generator interconnection queue, and existing demand by sector. To summarize the input data sources for the standard build of WIS:dom, Figure W-4 is displayed below.

Input ID	Input Name	Existing	New
1	Heat Rate	All Current Thermal Data	NREL ATB 2017 Value
2	Minimum Load	All Current Thermal Data	Fleet Average
3	Power Factors	All Current Generator Data	Fleet Average
4	Fuel Costs	All Current Thermal Data For Multiplier	NREL ATB 2017 Value
5	Fixed O&M Costs	All Current Generator Data	NREL ATB 2017 Value
6	Non-fuel Variable O&M Costs	All Current Generator Data	NREL ATB 2017 Value
7	Capital Costs	All Current Generator Data	NREL ATB 2017 Value
8	Relicense / Repower Costs	All Existing Nuclear, Wind, and Solar Generators	45% For VRE, N/A For Nuclear
9	Discount Rates	Uses Same Rate as "New"	5.87% Real
10	Economic Lifetimes	All Current Generator Data	NREL ATB 2017 Value
11	Transmission Costs	Uses Same Cost As "New"	ABB / Blended Existing Costs
12	Transmission Topolgy	Current Above 69 kV Aggregated To Reduced Form	New Lines Allowed Within WIS:dom; constrained by user
13	Demand	Current Demand By Sector	Growth Estimates Provided By Sector By VCE
14	Weather / Power Data	N/A	One Year Of Hourly Power Data For Wind & Solar Over EI
15	Policy & Regulations	Apply All Existing Policies & Regulations	Input As Constraints On Future Scenarios
16	Locational Multiplier	N/A	Black & Veach / NREL Public Data Combined By VCE

Figure W-4: Summary table of the major inputs to the WIS:dom optimization model, along with their sources.

The standard cost assumptions for all new builds of generators are provided by the NREL ATB. The values provided in the NREL ATB are averages for the whole US. WIS:dom converts national average values to localized ones via regional multipliers. There are regional multipliers for capacity and fuels and these are shown in Figure W-5.

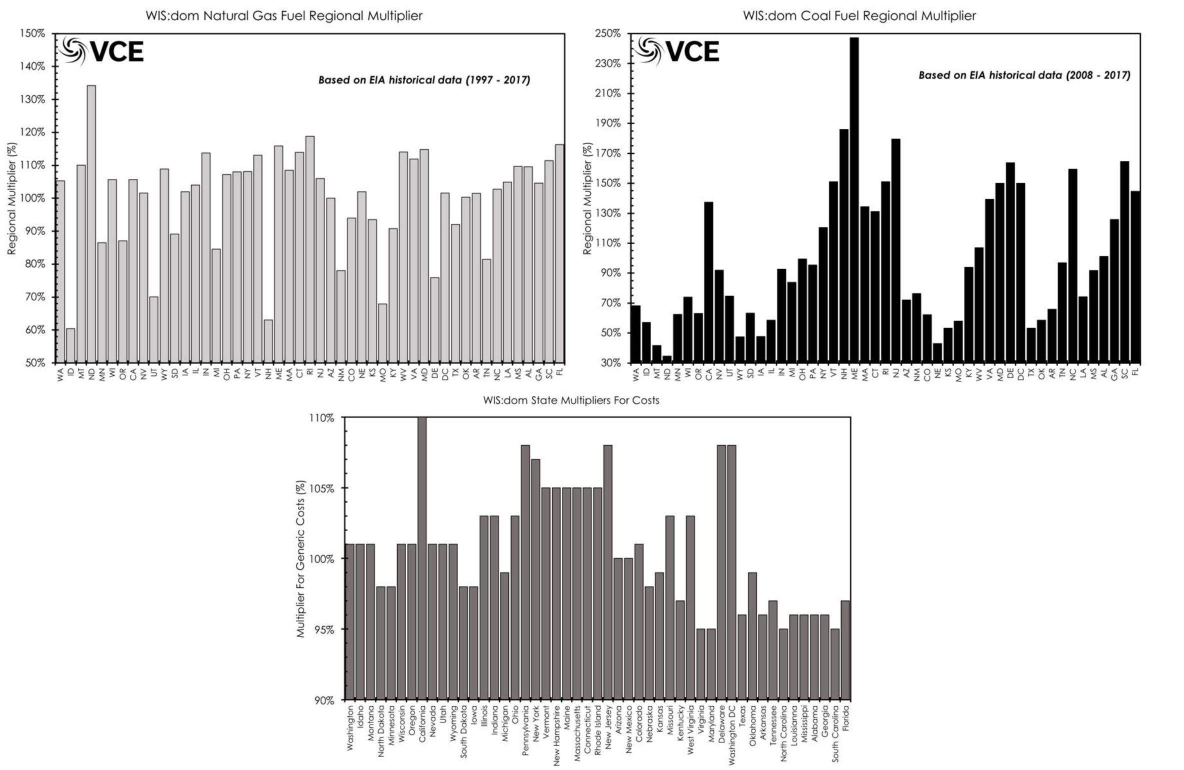


Figure W-5: The locational multipliers for each state in the US for natural gas fuel (top-left), coal (top-right) and generator siting (bottom). These multipliers convert the NREL ATB values into state values.

The NREL ATB 2017 cost values used in WIS:dom are shown in Figures W-6 to W-8. The heat rates and expected lifetimes are shown in Figure W-9. In addition to the regional multipliers, shown above, there is a temporal multiplier for natural gas throughout the year, to reflect the intra-annual variability of natural gas prices. WIS:dom has the ability to alter the inter-annual natural gas prices, between investment periods, by computing the elasticity between supply and demand; however, the capability was not used in this study.

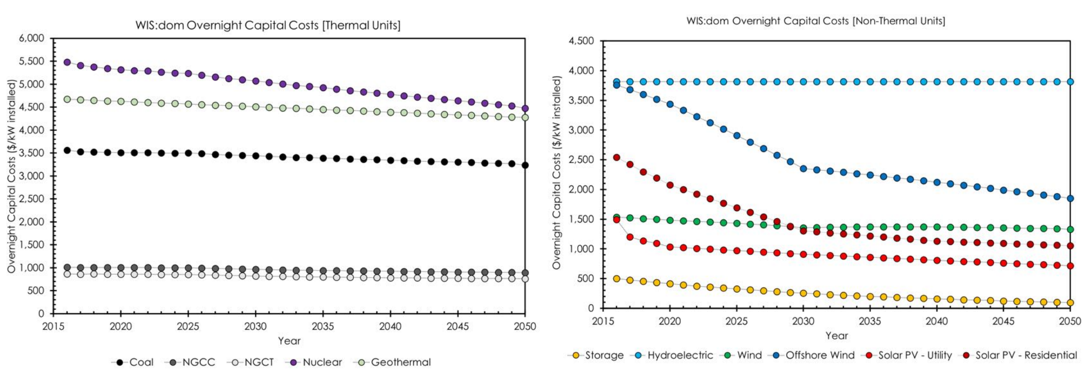


Figure W-6: The overnight capital costs (excludes financing cost & assumes a plant can be built overnight) in real $/kW-installed for thermal (left) and non-thermal (right) power plants in WIS:dom. All costs are from NREL ATB 2017, with the exception of storage costs, which come from Navigant / Strategen Consulting.

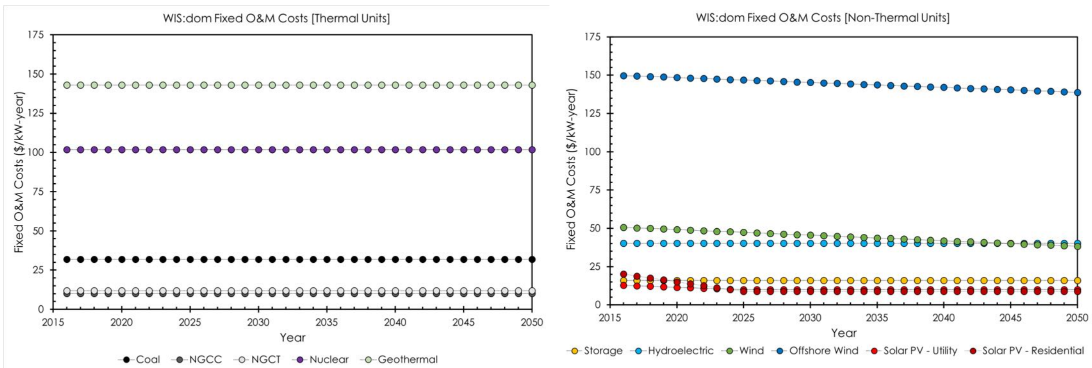


Figure W-7: The fixed operations and maintenance (O&M) costs in real $/kW-year for thermal (left) and non-thermal (right) power plants in WIS:dom.

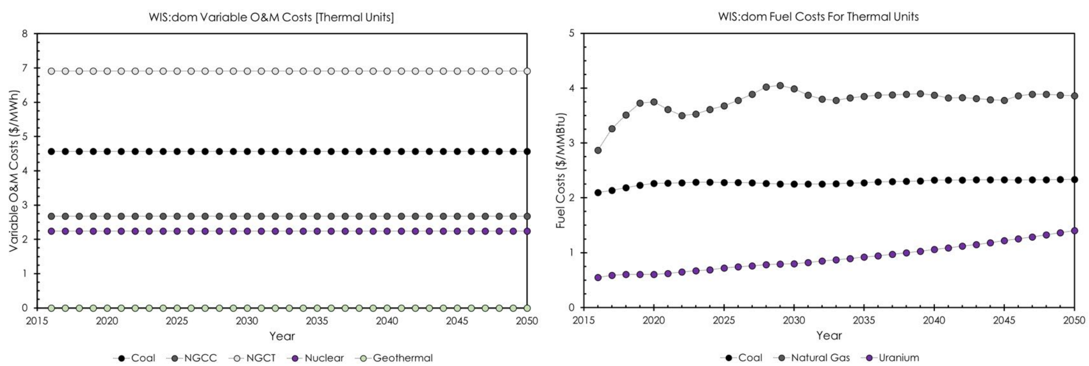


Figure W-8: The non-fuel variable O&M (left) and the fuel (right) costs for thermal generators in WIS:dom. The variable O&M costs are in real $/MWh, while the fuel costs are in real $/MMBtu. The non-thermal units have zero cost variable O&M as those costs are combined into the fixed O&M costs.

In addition to the capital costs, an important assumption is the cost of debt. WIS:dom uses the WACC (Weighted Average Cost of Capital) and it is assumed to be 5.87% (real) for all assets purchased by WIS:dom in its solver. Once a generator is connected to the grid, it has sunk capital costs. To retire that plant, WIS:dom must repay all the capital debt. Once the power plant is older than its economic life, WIS:dom can retire the power plant for no penalty. As power plants age, WIS:dom makes them less efficient to reflect the wear-and-tear.

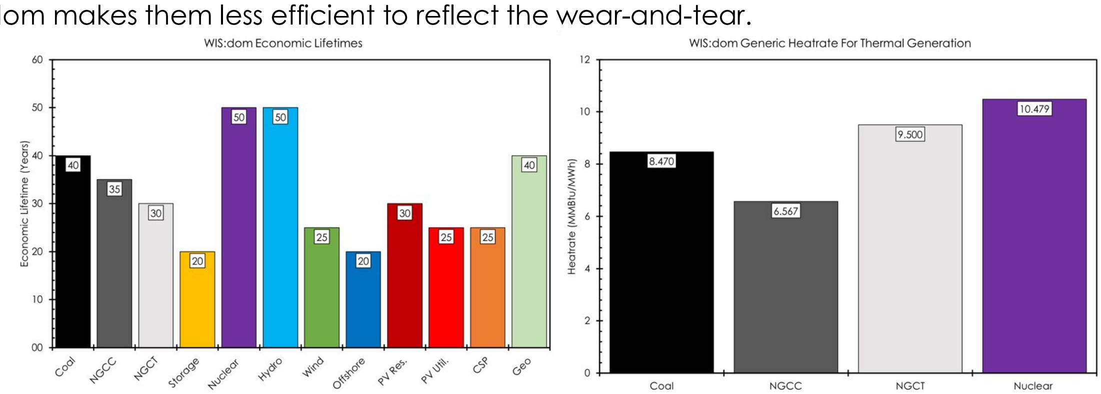


Figure W-9: The expected economic life for each generator (left) and heat rates for new thermal generators.

The WIS:dom optimization model must supply electricity demand for each 5-minute interval for, at least, an entire year across the footprint being solved over. It must do so while retaining operating (7% of 5-minute demand) and planning reserves (different for each region, but typically above 15%), and considering transmission power flow and associated losses. To do this, WIS:dom requires input load forecasts for each of the investment periods. WIS:dom is supplied the load data input at a county level. Within the demand profiles there can be electrification. These assets are known as demand-side resources and can be dispatched by WIS:dom. These features will be discussed more later, but in general, the load/demand data is separated into the sectors of residential, commercial, industrial, and transportation. The sector breakdown facilitates Demand Side Management (DSM), Demand Response (DR), Electric Vehicle (EV), heat pump transitions to all be accounted for and estimated for flexibility and growth/reduction on the demand side. For WIS:dom to deploy the demand-side resources in the dispatch it must pay for it. The cost of DSM is assumed to be inelastic. WIS:dom determines the level at which these resources are dispatched for each 5-minute interval. Figure W-10 displays the average amount of demand-side resources for flexibility by investment period and the cost to dispatch those resources.

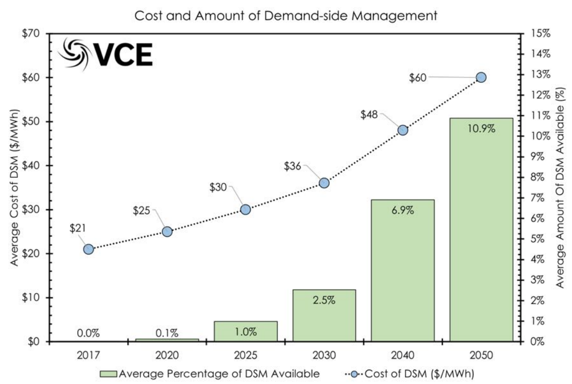


Figure W-10: The percentage of the demand each hour assigned to EVs and DSM (bars, right axis) and the cost of DSM to the energy provider in $/MWh (circles, left axis).

WIS:dom was built to be able to provide analytical rigor to analyzing policies, impacts and societal changes that result from the electricity grid evolving. It was specifically designed around incorporating vast amounts of weather data as well as generator, transmission, and customer operational data. To that end WIS:dom includes, as standard, the tracking and outputting of policy, economic, and pollution metrics. For example, WIS:dom tracks several species of pollution, namely: Carbon Dioxide (CO_2), Carbon Monoxide (CO), Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), Methane (CH_4), Nitrous Oxide (N_2O), Volatile Organic Compounds (VOC), and particulate matter ($PM_{2.5}$ and PM_{10}). The data from these pollutants are output by power plants and aggregated by state (typically). The plant-level data is stored. For special cases, the pollution is passed through the CAMx and EASIUR models from Carnegie Mellon University to determine the social cost impact of the pollution as well as the mortality and morbidity impacts. Since WIS:dom has such a fine granularity, CAMx can be explicitly driven by WIS:dom results; however, typically EASIUR provides a more rapid and state-level estimate that is adequate for most purposes. The pollution and emissions from the power plants is related to their heat rates, their emission controls, the fuel being burned, and the weather in the vicinity of the power plant. In addition to changes in pollution emissions, WIS:dom calculates the cumulative emissions, typically, by state to illustrate the buildup of emissions that are leaving the states into the atmosphere.

WIS:dom also computes and tracks the real-time costs of providing electricity as well as the average cost for each state over each investment period. In doing so, the model can estimate the impacts on rates and cost of electricity for consumers based upon the evolving composition of the electricity grid. Another important economic indicator that WIS:dom computes and tracks within the modeling framework is the full-time jobs that are created and destroyed in each state for each technology. Currently, WIS:dom does not possess estimates for the job numbers that would be provided by storage installations. VCE is working on building estimates for this. For all other technology types VCE uses publicly available data, particularly the NREL JEDI model for developing the inputs for WIS:dom to calculate the job impacts.

b. Logical & optimization operations

The WIS:dom optimization model can be considered a blended capacity expansion and production cost model. It is, therefore, a synthesis model. WIS:dom constantly seeks the lowest cost system(s) it is optimizing over; considering all the constraints and commitments built into the initialization. WIS:dom is typically run in linear programming (LP) mode. This means that all variables are real number values; allowing a more detailed inspection of the changes to the electricity grid composition. WIS:dom solves for each of the markets that are in entire footprint, while considering the transmission corridors between the markets, committed units for certain markets and some other market friction/inefficiencies. These can be relaxed with WIS:dom selecting transmission corridors to invest in over investment periods. Users of WIS:dom can constrain the amount of cooperation and transmission build out. Since WIS:dom is an LP optimizer, if transmission is completely constrained between markets, each market will be solved separately.

For the WIS:dom optimization model to solve, it must minimize the objective function, which is the sum of the total costs for each of the systems it is considering. The system costs include: capital repayments, fixed costs, variable costs, fuel costs, transmission costs, reserve payments, market clearing costs, integration costs, demand-side payments, retirement costs, and re-powering costs.

The minimization of the total system costs is under tension/pressure from the enforcement of constraints, which act to enforce reality on WIS:dom, and will change the composition of the solution vector; typically increasing the total system costs in the process. One of the important constraints is enforcing a market clearing price for each market, which is taken as the highest marginal cost of generator necessary to fulfill demand. This additional cost is added to the total system costs. Physically, these are not system costs, but profit, or revenue for the generators; but act to increase the cost to the overall system from the market perspective.

The main logic equations within WIS:dom are described in Figure W-11. The figure attempts to estimate the impact of each equation set.

Constraint ID	Equation Name	Equation Purpose	Impact Estimation
1	Total System(s) Cost Objective	To define the objective that is being minimized	**Critical** Other objectives may alter solutions significantly
2	Reliable Dispatch Constraint	Enforce WIS:dom meets demand in each region each hour without fail	**Critical** Strict enforcement of zero loss of load
3	Market Clearing Price Adjustment	Allowing WIS:dom to estimate the dispatch stack & attribute price vs cost	**Critical** Different market structures could impact deployment choices
4	DSM Balancing Constraint	Ensures that DSM providers can balance their demand	**High** Changing the description of DSM and costs could alter solutions
5	Transmission Power Flow Constraint	Produces the optimal power flow matrix and associated losses	**Critical** Transmission power flow significantly impacts dispatch and deployment
6	Transmission Capacity Constraint	Calculates the capacity of each transmission line	**Critical** Without this constraint, power flow could become artifically large
7	Planning Reserve Constraint	Ensure planning reserve margins are maintained	**High** Capacity credit for VREs can alter deployment decisions
8	Coal, NGCC, NGCT, Nuclear, Hydro, Geo Capacity Constraints	Maintain the capacity of generators above their peak production	**High** Without the constraints generations can be incredibly based on marginal costs alone
9	Storage Power & Energy Capacity Constraints	Complex equations & constraints to determine the utilization of storage	**Critical** Storage correctly modeled can change all investment decisions and dispatch
10	Coal, NGCC, NGCT, Nuclear, & Geo P_min Constraints	Constraints that force WIS:dom to adhere to P_min attributes for thermal generators	**Medium** P_min enforcement has lower impacts on decision
11	RPS & Emission Constraints	To enable WIS:dom to understand policy, regulatory and societal limitations	**Critical** When emissions enforced investment decisions are completely changed
12	Generator & Transmission Capacity Expansion Constraints	To require WIS:dom to keep investments in new generation & transmission to specific levels	**Low-Medium** Very tight enforcement could impact decisions, but realistic values do not substantial change solutions
13	Coal, NGCC, NGCT, Nuclear, & Geo Ramping Constraints	Describing the speed at which generators can alter their output for WIS:dom	**Medium** Faster ramping thermal generation is more favorable in lower emission scenarios, so this constraint impacts decisions in those cases
14	DER Deployment & Cost Constraints	Specifies to WIS:dom the amount of DERs to be constructed and/or cost to system of these assets	**Low** Has minimal impact on the overall system costs and investment decisions of utility scale generators
15	CIL & CEL Constraints	Describe the import & export limits between markets, countries, states, and interconnections	**Medium-High** Transmission expanding from existing lines & the addition of market impacts can dramatically alter decisions in some high emission reduction scenarios
16	Spatial Limitation Constraint	Allow WIS:dom to understand the space requirement for generators and competition for land use	**Medium** Without this constraint land use can be over used and over count the amount of generation in a location/site
17	Extraction Limits For VRE	Determines the limits to VRE extraction for nearby sites	**Medium** Impactful for wind siting considerations but much lower for solar PV siting
18	Nuclear & Hydro Dispatch Schedule	Informs WIS:dom that nuclear and hydro must conform to addition constraints regarding the water cycle, water temperature, and refuelling	**Low-Medium** Nuclear suffers a small amount due to offline times & hydro flexibility limited by constraint to assist with other VREs
19	Relicense / Repower Decision	Facilitates WIS:dom opting to relicense or repower an existing nuclear or VRE site	**Medium-High** Repowering can substantially improve existing sites at lower cost, while relicensing enable nuclear to remain within markets for longer
20	Load / Weather Forecast Error Estimator	Enables WIS:dom to detect regions with poor weather and/or load forecasts for consideration during investment decisions	**Low-Medium** Load & weather forecasts are small enough over EI markets that the invesments are not substantially altered. For WECC, the impact is much higher

Figure W-11: The main equation sets that WIS:dom computes and solves over during its optimization procedure. Not all equation sets are shown; only the most important to the study are displayed.

The equations described in Figure W-11 are initialized for each of the investment periods (2017, 2020, 2025, 2030, 2040, and 2050). WIS:dom solves for each investment period in chronological order. When WIS:dom completes a solve for an investment period, all the data / solution vectors are stored and passed to the next investment period to allow conditions to be constrained based upon previous decisions. In that way, WIS:dom is operating in "myopic mode". In other words, previous investment decisions impact future ones, but future ones do not impact previous decisions. To complete an investment period, WIS:dom must simultaneously: determine the generator capacity and siting, determine the transmission capacity and siting, determine the storage capacity and siting, compute retirement decisions, decide upon all the dispatch profiles for all the generation and transmission, compute the cost for each market region, incorporate the VRE dispatch based upon weather drivers, calculate the emissions produced at each site, and finally conform to every constraint imposed (without fail).

One of the most unique features of WIS:dom (in addition to the high temporal granularity of the dispatch over a long time period and spatial scale) is its ability to site the generators, storage, transmission, and demand-side resources. It does this at a 3-km resolution. Therefore, after a simulation is executed, a user can get the specific siting, capacity, transmission necessary for each asset within the footprint. WIS:dom is not a replacement for a full stability study or AC power flow analysis, rather it is a synthesis model that encompasses the combined capabilities of traditional production cost and capacity expansion models. By performing its solving sequence in this manner, WIS:dom facilitates information exchange between the different scales while co-optimizing the build out of assets. In short, WIS:dom allows more solution options and more information for the model to base its decisions upon, thus finding new pathways that are not available to other modeling platforms that exist in the market today.

Another assumption/input that WIS:dom accounts for in its internal logic is the constraints on nuclear and hydroelectricity generation with regards to weather and refueling schedules. Hydroelectricity is heavily dependent on the weather, and nuclear has somewhat strict maintenance and refueling schedules. This manifests with the fleet of nuclear and hydroelectricity changing their capacities month by month. For WIS:dom, VCE determined the last 10 years of data for the nuclear fleet cycling due to maintenance and refueling and apply the average of those 10 years to the nuclear fleet (specified by state). For hydroelectricity, WIS:dom is forced to release the same amount of water as was released in the weather years for each 5-minute interval. The implication for hydroelectricity is that it can be more flexible to changing electricity grid mixes, but must retain steady water flow as to not alter other uses for the water. This is done because many hydropower plants are run-of-river and cannot store the water and others are used for many other purposes other than electricity generation. A final reason to deal with hydropower in this way is to consider the changing weather patterns and how they influence the stream flows for the hydropower.

WIS:dom incorporates existing generation, existing short-term queue, existing transmission, proposed transmission (if required), retirement dates (enforced or economic), set pathways, emission targets, RPSs, EV projections, DSM/DR projections, and other aspects warranted.

c. Weather, power, demand, & technology resource descriptions

The weather data used in WIS:dom includes 3-km and 13-km hourly granularity as well as 5-minute data at 3-km. These data run over 5 to 13 years. The weather data years are 2006 to 2018 at 13-km, hourly and 2014 to 2018 at 3-km, 5-minutely. VCE has created sophisticated algorithms (the Solar Power Model and the Wind Power Model) to convert the weather data to variable power potential. The weather data is also used to constrain the load forecasts, alter the power flow potential, and determine extreme events within the system. The weather data is based upon NOAA NWP data assimilation that includes 10,000 - 25,000 observations each hour. The observations include aircraft, ground-based measurements, satellites, radar, and more. With the high density of observations, the data-assimilation is utilized to create an approximation to the state of the atmosphere at a given time. VCE takes the data assimilation and strengthens the correlation between observations and model. VCE also considers the forecast errors that appear in weather models and creates unique time series for each of the resource sites in the US. The time series for each resource site is then processed to create potential variable generation and is then further used in estimating electric loads for each resource site. Finally, the data is calibrated along transmission lines to determine the rating of the existing transmission infrastructure. The weather data is assembled in a database structure only readable by WIS:dom. The purpose of the database is that it is interchangeable with other weather datasets (if necessary) for comparison or dispatch characteristics under various scenarios. A further benefit of the database structure is that the WIS:dom optimization model can read in the dataset in less than 5 minutes for ~2 million resource sites and 105,120 5-minute timesteps.

For existing wind and solar sites, existing parameters were input into the wind and solar power models to overwrite the potential VRE resource. If WIS:dom determines repowering a site is worthwhile, the potential VRE resource will replace the existing values when the repowering takes place; thus, providing the enhancement to the generation at that site. The siting constraints for the whole US are calculated by VCE using the latest (and highest resolution) land use datasets. The datasets allow WIS:dom to have realistic bounds on siting for the variable generation. Figure W-12 displays the land use data set that is incorporated into WIS:dom for siting constraints of renewables. Figure W-13 shows the wind (at 80m) and solar PV (single axis tracking) potential over the United States.

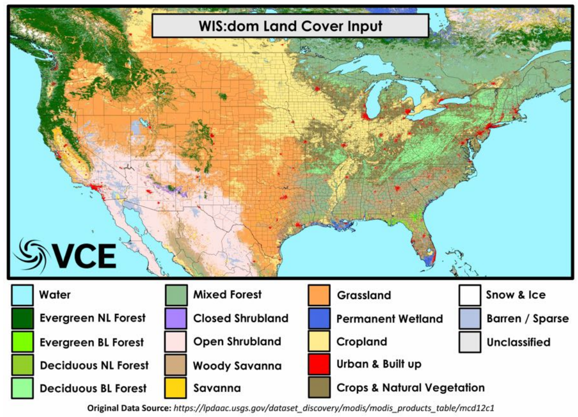


Figure W-12: The land use dataset that is used within WIS:dom to determine the appropriateness of locations for development of variable generation. Other layers are applied to the land use dataset, such as topographic, critical species, migration paths, etc.

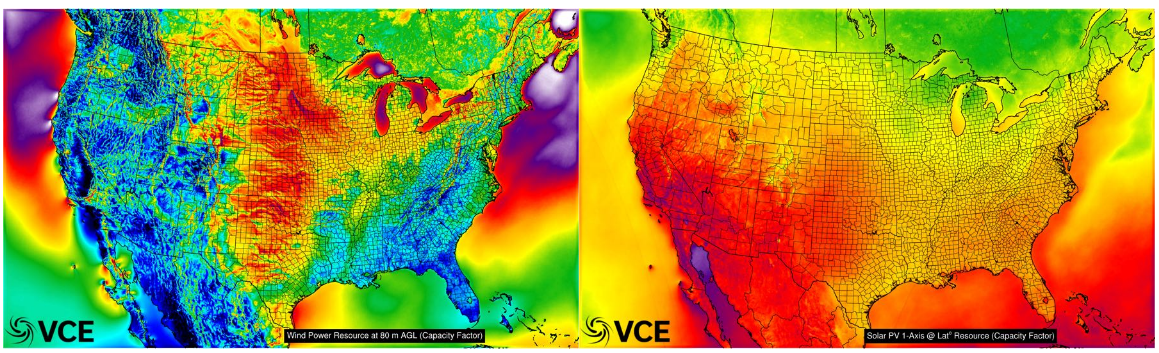


Figure W-13: The average wind (left) and solar PV (right) resource potential for the US. The potential is defined in capacity factors. WIS:dom includes multiple sub-categories in each generation type.

The land use dataset depicted in W-12 is used with other datasets to determine the potential siting locations for generators. The upper limits provide guidance to WIS:dom about the appropriateness of a region for different technologies and what resources are available. The WIS:dom optimization model can have more information added for constraints within its siting procedure. Figure W-14 shows the standard siting limitations for wind, solar PV, and rooftop PV. To determine the rooftop PV siting constraints, VCE produced a screening procedure to determine the number of rooves available per 3-km grid cell, estimated the angle of the rooves and calculated the capacity available for energy production.

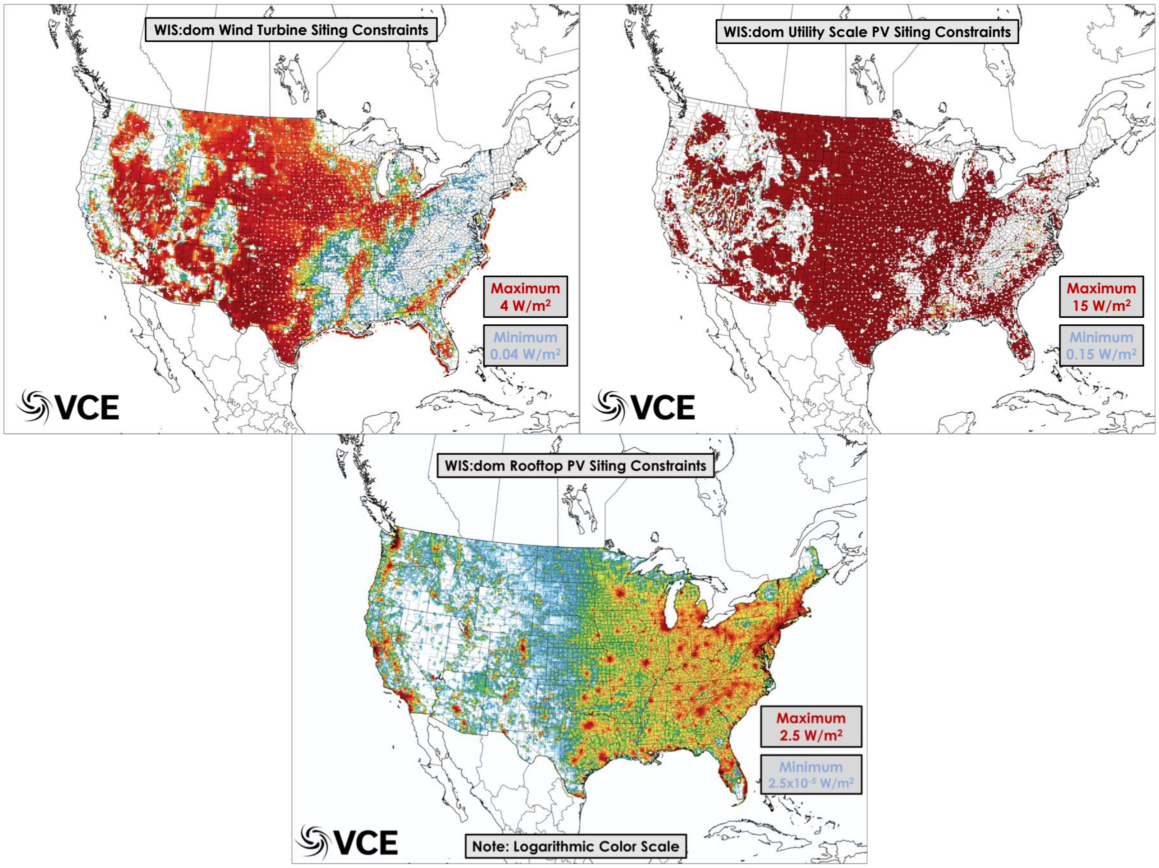
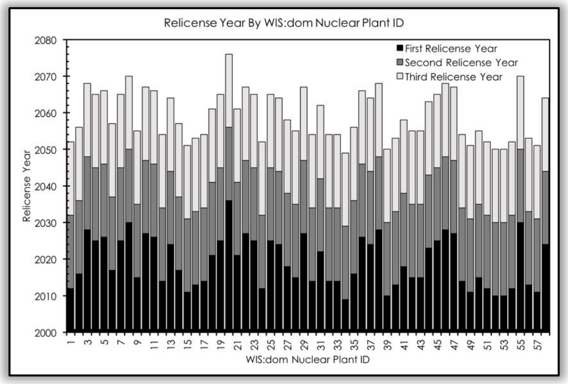


Figure W-14: The wind (top-left), utility-scale PV (top-right) and rooftop solar PV (bottom) siting potential across the CONUS footprint.

For the demand-side resources, WIS:dom assigns a value to each 5-minute interval for flexibility based upon the demand mix (the electrification amount, the composition in terms of EVs, water heaters, heat pumps, etc.). The two largest areas for flexibility are EVs, DSM (primarily representing space and water heating in residential and commercial sectors), and DR (almost entirely interruptible industrial demands). WIS:dom assigns a price to EV charge shifting, DSM and DR within the WIS:dom market. The cost is to allow WIS:dom to recognize that there are costs to providing flexibility. The demand-side resources are full participants in the energy markets and can be dispatched by WIS:dom as such. The principle behind the modeling of the flexibility resources centers around the input load profiles. VCE estimates the native load, in the absence of price signals or generation scarcity. Simply put, how would the demand behave if left to the environmental, physical and human constraints on the system. WIS:dom, when solving, has the ability to remove some of the demand, for a cost, and shift it to another time period, or simply provide the native demand with generation.

One final important distinction needs to be made with respect to WIS:dom's handling of nuclear power plants. They are processed differently to other thermal generators because of their need for relicensing. For each of the nuclear power plants, the relicense costs and dates (as well as fixed costs) are estimated and included in WIS:dom. The values are shown in Figure W-15. Once a nuclear power plant reaches its relicense date WIS:dom must decide whether to relicense the plant or retire it, and replace it with other generation. Of course, WIS:dom can construct a new nuclear power plant, and those decisions are based on the input costs for new builds. A new relicense schedule is developed for new plants. First relicense after 40 years and the second after 60 years.



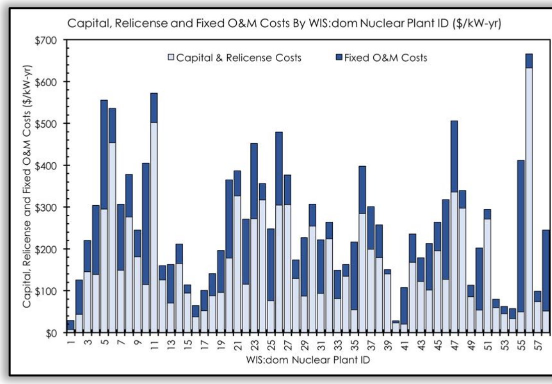


Figure W-15: Relicense year by nuclear plant ID (left) and relicense and fixed O&M costs by nuclear plant ID (right). The names of the nuclear power plants are removed purposely.

d. Overall WIS:dom Functionality

Resource Siting Constraints:

- Wind and solar have a base GIS data layer for forbidden development sites;
- Conventional generation is limited to current or specified sites;
- Grid tied storage can be sited in utility or Behind the Meter;
- Distributed Energy Resources can only be sited in urban areas;
- Can model the entire US, but typically reduced to interconnect or ISO/RTO;
- Spatial constraints are applied within the gridded data to ensure no double use.

Transmission Expansion Constraints:

- Transmission upgrades can be limited by the user/client;
- Transmission and storage can be considered together as similar style assets;
- Explicit lines of interest can be included to determine the benefit/disadvantage of the lines;
- Multiple optional expansion can be offered to the model and it will determine the least-cost built out, while simultaneously considering the generation and load at dispatch intervals.

Inter- and Intra- Annual Weather Datasets:

- A minimum of 3 years of hourly weather data is always available used;
- The hourly data can be at 13-km or 3-km (or both, if desired);
- The hourly data can also include forecasts (2-hr, 6-hr), to assess the impact of forecast error [for real-time dispatch in WIS:dom];
- 3-km 5-minute data is also available for the model;
- Capacity credit evaluation based upon various penetrations and weather variability.

Interconnection Influences of External regions:

- Model different geographic scales to determine the adjustment to client's plans based upon external influences;
- Geographic extent available: National; Eastern Interconnect, MISO, Michigan, Utility only (note other areas are available if utility is in other US regions);
- Rapid sensitivity analysis available with batch mode running optional.

Distributed Resources and Other Considerations available:

- Electric vehicle adoption;
- Sector electrification and load shape changes;
- Residential/Commercial storage;
- Rooftop solar PV;
- Demand response/management;
- Role of charging/discharging vehicles on grid;
- Planning and following reserve requirements in a changing resource mix.

Main Technologies Available in the WIS:dom Optimization Model:

1. Solar Photovoltaics
    a. Fixed axis,
    b. 1-axis tracking,
    c. 2-axis tracking,
    d. Rooftop solar PV;
2. Grid tied energy storage
    a. Li-Ion,
    b. Flow batteries;
3. Wind Turbines
    a. 80 m hub height,
    b. 100 m hub height,
    c. Other [120-160 m] hub heights,
    d. Turbine designs,
    e. Rotor diameter;
4. Electric Vehicles
    a. Charging/discharging behavior,
    b. Amount and location of EVs,
    c. V2G, G2V, etc.;
5. Distributed Energy Resources
    a. Storage,
    b. Heat pumps,
    c. Other demand management;
    d. Large scale demand management.

VII. WIS:dom Output Data Files Description

A. Data and Images All Reside within this google drive folder: https://drive.google.com/open?id=1yUnLVDTXC7dIgbIjJ1_VFGeOPNnyF-su
B. Images for all the scenarios are constrained in this hyperlink: https://drive.google.com/open?id=19yIYUYojEisKJ9hsOpEdH3IuTlZ7oA2h
C. The scenario data are contained in zip files. Unzipping each file will require ~7 GB of space, *so please beware*! The spreadsheets and images should suffice for most purposes. The data files contain all the dispatch files that aggregate for states and the whole Eastern Interconnection, transmission power flow between states, location (latitude and longitude) of installations, emissions, costs, etc. All files are reduced in size using k-means clustering (Lloyd's algorithm) to 13-km & hourly from the 3-km 5-minutes. Otherwise each directory would be ~1,500 GB rather than the ~7 GB.
D. This end of study presentation and summary images are also available: https://drive.google.com/open?id=1ARU9aQ2YGuXAVjr27w9LR9Kg8IVBrkng
E. Each set of images have the same numbering format. **001 to 053 are for the aggregate Eastern Interconnection values**. Some images are broken down to individual states, while others are aggregated by EI. Each image has a title and labeled axes. Further, for all the scenarios the images can be found in the accompanying spreadsheet, where the data for the image is also contained. **Images 054 to 087 are specific to Minnesota**. The images include the dispatch within Minnesota, the capacity installed, the emissions, the cost of electricity, the generation share, and jobs. **Images PowerPlants_XXX are the spatial data** for the installed capacity across the Eastern Interconnection. Further, the images show the interstate transmission capacities.
F. The data in the spreadsheets are linked to data in the zipped files. There is more data in the zipped files than in the spreadsheets. The additional data is focused on the dispatch, power flow, capacities, hourly emissions, *plant data for Minnesota – namely, hourly costs, emissions, dispatch for each plant in Minnesota*.
G. Each data file that has a number at the front is for a specific year. They are numbered 1 to 6 and they represent 1=2017, 2=2020, 3=2025, 4=2030, 5=2040, 6=2050.
H. Inside the data files are different levels of data. When there is a "state" in the file name, that means that each state is represented in the file. Normally, a summation for each state, which are denoted in the model as the following:
1 = WA, 2 = ID, 3 = MT, 4 = ND, 5 = MN, 6 = WI, 7 = OR, 8 = CA
9 = NV, 10 = UT, 11 = WY, 12 = SD, 13 = IA, 14 = IL, 15 = IN, 16 = MI
17 = OH, 18 = PA, 19 = NY, 20 = VT, 21 = NH, 22 = ME, 23 = MA, 24 = CT
25 = RI, 26 = NJ, 27 = AZ, 28 = NM, 29 = CO, 30 = NE, 31 = KS, 32 = MO
33 = KY, 34 = WV, 35 = VA, 36 = MD, 37 = DE, 38 = DC, 39 = TX, 40 = OK
41 = AR, 42 = TN, 43 = NC, 44 = LA, 45 = MS, 46 = AL, 47 = GA, 48 = SC, 49 = FL.
I. The dispatch files, or other files that are done by time steps for each investment period have 8,403 hourly values for each variable they are describing. This is done for costs, LCOE, pollution, dispatch, etc. This is a product of taking the 105,120 5-minute intervals and clustering them around the 8,403 cycles of hourly weather data that VCE created. This allows VCE to compares results directly with the hourly version of WIS:dom.
J. There are also files that have each of the class of generation split out for interpretation:
1 = Coal, 2 = NG CCGT, 3 = NG CT, 4 = Storage, 5 = Nuclear, 6 = Hydroelectric, 7 = Wind, 8 = Offshore, 9 = Rooftop PV, 10= Utility PV, 11 = CSP, 12 = Geothermal, 13 = CCS.