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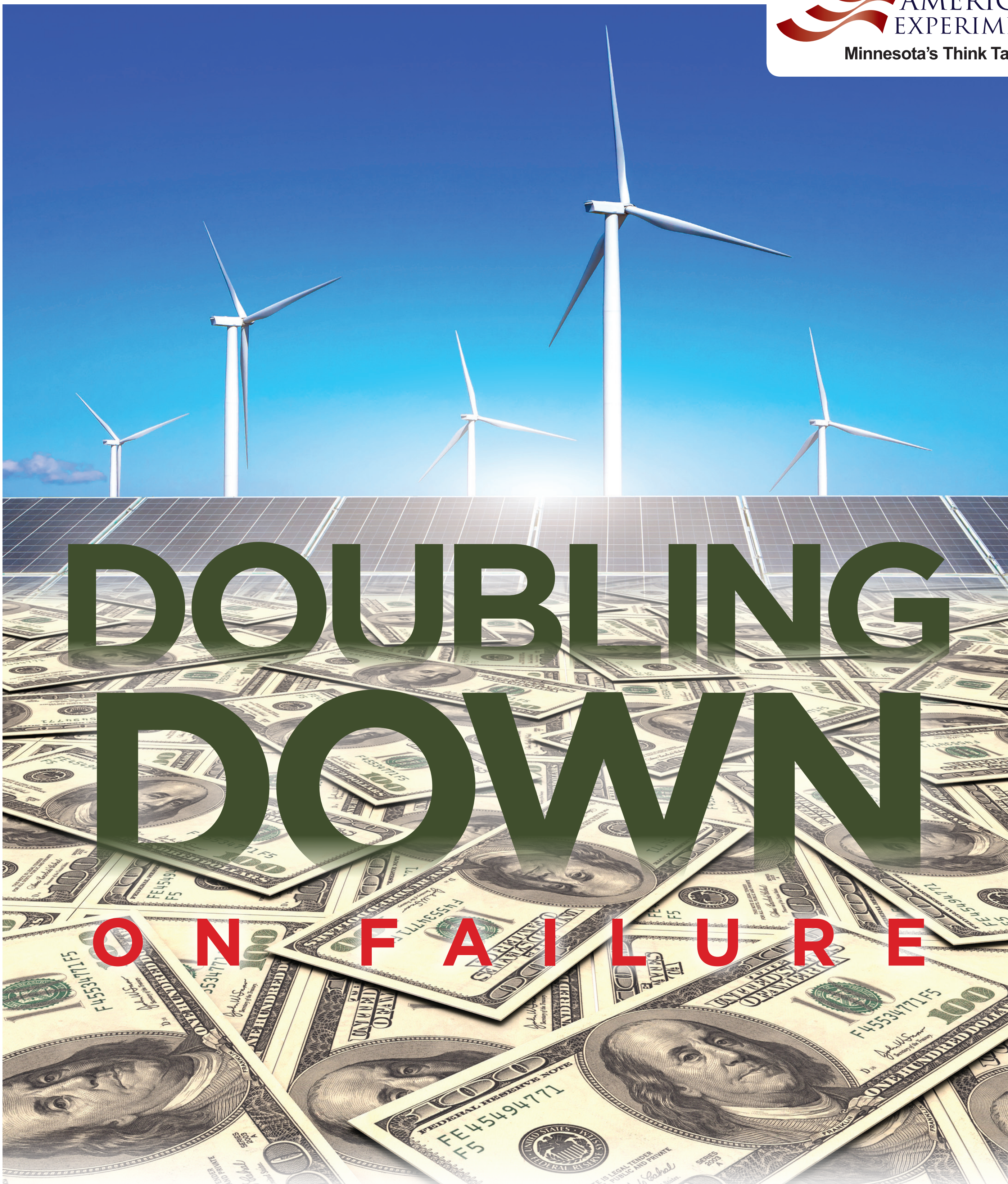

DOUBLING DOWN ON FAILURE

How a 50 Percent by 2030 Renewable Energy Standard **Would Cost Minnesota $80.2 Billion**

ISAAC M. ORR, MITCH ROLLING, AND JOHN PHELAN

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Executive Summary

Minnesota currently has a law mandating that 25 percent of the state's electricity come from renewable energy sources, like wind and solar, by 2025. Some lawmakers have proposed doubling the renewable energy mandate (REM), requiring that 50 percent of our electricity be generated by renewable sources by the year 2030, and Governor Walz has proposed a 100 percent carbon-dioxide-free electric grid by 2050.

This report chose to calculate the impact of a 50 percent REM, rather than a 100 percent REM, because research from the Massachusetts Institute of Technology shows using wind, solar, and batteries to achieve 100 percent of electricity generation would be exponentially more expensive than a 50 percent renewable benchmark.

Doubling down on the REM will increase electricity costs by $24.6 billion by 2030, and the additional costs of maintaining this electric system through 2050 will be nearly $80.2 billion.

In contrast, building new nuclear power plants would provide the same amount of carbon-dioxide-free electricity at a much lower cost than wind and solar. This is likely a key reason Xcel Energy announced its electricity would be 100 percent "carbon free," and not 100 percent "renewable," by 2050.[1]

Policymakers have a duty to the hardworking people of Minnesota to enact policies that maximize benefits while minimizing costs. If lawmakers enact a 50 percent renewable energy mandate, they will be doubling down on a failed and expensive policy that imposes significant harm on Minnesota families and businesses with negligible environmental benefits.

We have calculated the high cost of doubling the renewable energy mandate in a "Renewable" scenario, and offer two lower-cost and more effective alternatives, Short-Term Nuclear and Long-Term Nuclear, that maximize cost savings for Minnesota families and businesses while still reducing carbon dioxide emissions. Lastly, we present a scenario based on the proposed Affordable Clean Energy (ACE) rule promulgated by the U.S. Environmental Protection

Agency that establishes new regulations designed to reduce carbon dioxide emissions from existing coal-fired power plants.[2]

We offer this executive summary and seven policy recommendations based on our findings. Enacting a 50 percent renewable energy mandate by 2030 would:

Increase electricity costs by $80.2 billion to meet mandated renewable energy goals and maintain this electric system through 2050. This cost is far more than the Short-Term Nuclear, Long-Term Nuclear, or ACE scenarios. The 50 percent renewable energy mandate described under the Renewable scenario would cost an additional $80.2 billion through 2050 compared to 2016 costs. The Short-Term Nuclear scenario would increase costs by $58.2 billion, the Long-Term Nuclear scenario would increase costs by $27.7 billion. The ACE scenario would reduce costs by $7.5 billion through 2050.

Cost each Minnesota household $1,200 per year through 2050. Building and maintaining an electric grid built to accommodate renewable energy resources would cost each Minnesota household an average of $1,200 per year, relative to 2016 prices. Each Minnesota household would pay an additional $867 under the Short-Term Nuclear scenario and $410 under the Long-Term Nuclear scenario every year through 2050, compared to 2016 prices, but only a small portion of this will appear on their monthly utility bills.

Maintaining and upgrading Minnesota's existing coal-fired power plants under the ACE scenario would reduce electricity costs, saving Minnesota households an average of $112 per year.

Cause electricity prices to increase by more than any other scenario. The Renewable scenario would cause electricity prices to increase an average of 4.18 cents per kilowatt hour (kWh), increasing the total retail price of electricity by 40.2 percent relative to November 2018 prices.[3]

The Short-Term Nuclear scenario would increase costs by an average of 3.03 cents per kWh, the Long-Term Nuclear scenario would increase costs by 1.45 cents per kWh. In contrast, the ACE scenario would reduce electricity costs by 3.8 percent.

Increase household electric bills by $375 per year, a 32 percent increase compared to 2017. Increasing electricity costs will have far-reaching negative consequences for Minnesota families, especially low-income families and seniors, schools, hospitals, and businesses, and harm our economy as a whole.

Because doubling down on Minnesota's renewable energy mandate would cause the price of electricity to rise by 4.18 cents per kWh under the Renewable scenario, the average Minnesota household using 748 kilowatt hours of electricity every month will see its monthly bill increase by $31.24 per month, or $375 per year.[4, 5]

Yearly electric bills would rise by $272 under the Short-Term Nuclear scenario, $130 under the Long-Term Nuclear scenario, and Minnesota households would save $35.10 per year under the ACE scenario through 2050.

Force the Edina school district to lay off 10 teachers to make up for higher electricity prices. Edina schools use 13.8 million kWh of electricity every year.[6] Increasing the price of electricity by 4.18 cents per kWh would result in increased electricity costs of approximately $576,425. Edina would have to lay off more than 10 teachers making $56,000 per year to pay these higher electric bills or raise property taxes to keep them on staff.

Destroy 20,950 jobs by 2050 and reduce Minnesota's GDP by $3.1 billion every year to create temporary construction jobs. Renewable energy advocates claim the renewable energy industry has created 7,241 jobs in Minnesota, but nearly all of these jobs are temporary construction jobs.[7]

In contrast, the economic modeling software IMPLAN shows higher electricity prices from renewable energy will destroy 20,950 more permanent jobs through 2050.[8] Higher electricity prices in the Short-Term Nuclear scenario would result in a loss of 13,916 jobs, and the Long-Term Nuclear scenario would result in a loss of 6,745 jobs through 2050.

By reducing the cost of electricity relative to 2018 prices, the ACE scenario would result in an increase in employment of 1,518 jobs.

Harm energy-intensive industries, such as agriculture, healthcare, manufacturing, and mining, the most. As electricity prices rise, job losses would likely be most significant in industries where electricity use is a large expense, such as agriculture, healthcare, manufacturing, and mining. These job losses would hit hardest communities like Austin, Rochester, St. Cloud, and Hibbing.

Cement our need for fossil fuels for decades. Despite the common belief that wind and solar power can replace reliable forms of electricity like coal or natural gas, renewable energy makes fossil fuel energy indispensable. This is because regardless of how much wind or solar power is built there will be times when they produce zero electricity. During these times, we would still rely on natural gas and coal-fired power plants to generate the electricity we all depend upon.

Both nuclear scenarios would reduce Minnesota's reliance on fossil fuels because nuclear energy does not need backup coal or natural gas generation. Nuclear power can therefore reduce, rather than merely periodically displace, our reliance on fossil fuels.

Fail a cost-benefit analysis, as determined by the Minnesota Public Utilities Commission. The cost of reducing one metric ton of carbon dioxide while providing reliable electricity using wind and solar would eclipse $135 through 2050, while the Short-Term Nuclear and Long-Term Nuclear alternatives would cost $113 and $125 per metric ton of CO_2 averted, respectively.

The cost of reducing CO_2 emissions in each of these scenarios vastly exceeds the Social Cost of Carbon (SCC) values assigned by the Minnesota Public Utilities Commission (PUC), which range from $15.20 to $69.48 per short ton by 2050.[9]

This means the Renewable scenario, the Short-Term Nuclear scenario, and the Long-Term Nuclear scenario would each spend more money to avert carbon dioxide emissions than the anticipated economic damages of each marginal ton of carbon dioxide emitted into the atmosphere; thus, failing a proper cost-benefit analysis.

Reduce Minnesota's share of carbon dioxide emissions by only 0.0006 of the global total by 2030. Doubling Minnesota's renewable energy mandate would reduce CO_2 emissions from Minnesota's electric generating plants from 0.0283 gigatons (28.3 million metric tons) in 2017 to 0.0052 gigatons (5.2 million metric tons) in 2030.

In 2018, global fossil-fuel-related CO_2 emissions reached 37.1 gigatons, meaning Minnesota's entire electric sector accounted for 0.00075 of global CO_2 emissions.[10] Therefore, doubling Minnesota's renewable energy mandate would bring our emissions down from 0.00075 to 0.00013 of global CO_2 emissions. These reductions in CO_2 would potentially avert 0.0006° C of warming by 2100, an amount far too small to be measured.

Because greenhouse gases mix evenly in the air, Minnesota would still incur 99.94 percent of the warming impact caused by rising greenhouse gas emissions from other states and countries. This is not to say we should throw our hands up and do nothing, but we must be realistic about the costs that will be borne by Minnesotans and the comparatively small benefits they or anyone else would reap.

Policy Recommendations

Our research leads us to seven common-sense policy recommendations that would reduce the costs of electricity in Minnesota and offer more affordable, and more effective, options for reducing carbon dioxide emissions than renewable energy sources such as wind and solar. If adopted, these recommendations would save Minnesota electricity consumers billions of dollars in the coming decades.

1) Direct the Minnesota Public Utilities Commission and electric companies to study the feasibility of fully implementing the ACE rule. The ACE scenario is the only scenario examined that passes a cost-benefit analysis based on Social Cost of Carbon estimates established by the Minnesota Public Utilities Commission through 2050. Therefore, Public Utilities Commissioners should examine and instruct electric utilities to study the feasibility of the ACE rule and, if appropriate, implement it as a means of complying with Minnesota state statutes that direct utilities to aim for electricity rates to "be at least five percent" below the national average.[11]

2) Legalize the construction of new nuclear power plants in Minnesota. Minnesota state law has prohibited the construction of new nuclear power plants since 1994.[12] If Minnesota lawmakers want to show true leadership on reducing CO_2 emissions, they should seek to provide the greatest and most sustainable reduction in emissions for the lowest possible cost. Ending Minnesota's nuclear ban is the only way to provide reliable, affordable, baseload power with no carbon dioxide emissions.

Minnesota lawmakers should designate a task force to explore least-cost solutions for nuclear power—including Generation III reactors built by South Korean firms that recently have been granted key safety and design approvals by the Nuclear Regulatory Commission (NRC)—and Small Modular Reactors (SMR).[13]

3) Utilize existing coal and natural gas plants for the entirety of their useful lifetimes. Minnesota ratepayers have financed billions of dollars in existing coal and natural gas infrastructure and deserve to reap the benefits of their investment through lower electricity prices: $52.8 billion under the Long-Term Nuclear scenario, or $88.1 billion under the ACE scenario over the coming decades, compared to the cost incurred in the Renewable scenario.

If Minnesota lawmakers are truly serious about reducing emissions and providing a just, equitable, and affordable transition to carbon-dioxide-free electricity, they should legalize new nuclear power plants and pursue the Long-Term Nuclear scenario, which would save Minnesota households $790 every year compared to renewable energy without compromising environmental quality.

Furthermore, using existing power plants until they reach the end of their useful lives allows for advances in nuclear technology, such as the SMR that are currently being planned for construction at the Idaho National Laboratory, to reduce costs and increase unit flexibility while providing safe, reliable power.[14]

4) Require utility companies to factor in the cost of "load balancing" with natural gas backup for renewables in their Renewable Energy Standard Rate Impact Reports. Utilities must report the cost of renewable energy in their Renewable Energy Standard Rate Impact Reports, but they currently are not required to detail the cost of natural gas sources needed to ensure reliable electricity.[15] These are significant costs that should be attributed to Renewable Energy Standards, along with additional property tax expenses and the impact of these policies on utility profits. Minnesotans deserve to know the total cost of renewable energy.

5) Repeal the Next Generation Energy Act, or amend it to include all sources of electricity that do not emit carbon dioxide. If Minnesota lawmakers are sincere in their belief that we must reduce carbon dioxide emissions as soon as possible to limit the warming impact of greenhouse gases, they must end special carve-outs for wind and solar and include all carbon-dioxide-free sources of electricity such as nuclear, large hydroelectric power, and fossil fuel technologies that utilize carbon capture and sequestration, all of which would be more reliable and provide value superior to wind or solar.

6) End the Community Solar Garden program. Community Solar Gardens (CSG) in Minnesota would provide just 3 percent of electricity production if a 50 percent renewable energy mandate is imposed, but represent 7 percent of the costs (see the idle capacity discussion in Appendix I). This program is a liability, not an asset, and guaranteed payments to CSG operators should be phased out by 2020.

7) Acknowledge that increasing Minnesota's renewable energy mandate would be doubling down on failure. Mandating that 50 percent of Minnesota's electricity come from wind and solar would be doubling down on an expensive policy that would cost Minnesotans $80 billion and avert only 0.0006° C of warming by 2100. If the main reason lawmakers want to enact this mandate is to prevent global warming, they will cost Minnesota families $1,200 per year while failing to make a measurable dent in global temperatures.

Contents

Introduction

Electricity is an important component of every facet of our modern lives. It has become as indispensible to our well-being as air, water, food, and shelter. For our state to thrive, everyone needs access to reliable and affordable electricity.

Many people believe that shifting away from fossil fuels to wind and solar power to generate this needed electricity is necessary for the environment, economically advantageous, and will be relatively easy to achieve. The facts dictate otherwise. Our research shows obtaining even 50 percent of Minnesota's electricity from renewable energy sources, primarily wind and solar, by 2030 would cost Minnesotans an additional $24.6 billion by 2030, and $80.2 billion through 2050.

Section I of this paper describes the costs and emissions profiles of four potential scenarios for Minnesota's energy future: a "Renewable" scenario, which details the costs of a 50 percent renewable energy mandate; a Short-Term Nuclear (STN) scenario, which describes the costs of building new nuclear power plants before 2030; a Long-Term Nuclear (LTN) scenario, which would gradually replace aging coal and natural gas plants with nuclear power as they retire; and an Affordable Clean Energy (ACE) scenario, which details the costs associated with complying with the U.S. Environmental Protection Agency proposed rule requiring efficiency improvements to reduce carbon dioxide emissions from existing coal-fired power plants.

Section II explains how high electricity prices harm Minnesota families and destroy jobs. These negative impacts are felt most acutely by low-income households and in energy-intensive industries such as agriculture, healthcare, manufacturing, and mining.

Section III explains why a 50 percent renewable energy mandate will have virtually no environmental benefits, despite its high cost.

Section IV offers concluding remarks.

Appendix I explains how the costs of generating electricity in Section I were calculated, further elaborating on how a 50 percent renewable mandate will drive up the cost of electricity in Minnesota, and why nuclear power plants could achieve the same reduction in carbon dioxide emissions for far less cost.

Section I: Electricity Costs and Emissions Under Four Scenarios

Many people believe replacing coal-fired power plants with renewable energy is as straightforward as building wind turbines and solar panels, which produce "free energy."

In fact, renewable energy is not "free." The proponents of renewable energy mandates routinely ignore the large, up front capital costs, the cost of load balancing—providing electricity when the wind is not blowing or the sun is not shining—transmission costs, property taxes, and utility profits. All of these are major costs associated with adding wind and solar to the electric system.

Our study takes all of these factors into account and therefore provides a more comprehensive and realistic picture of the cost of providing reliable electricity while integrating intermittent wind and solar onto Minnesota's electric grid. Our results show switching from coal and natural gas to nuclear power would be expensive but far more affordable than wind and solar for carbon-dioxide-free electricity.

Renewable scenario. The Renewable scenario calculates the generation mix and cost of enacting a 50 percent renewable energy mandate where electricity is produced primarily by wind and solar. Figure 1 shows the contribution of each generation source.

Under this scenario, 79 percent of electricity would come from sources that do not emit carbon dioxide. Wind would constitute 45 percent of generation, 23 percent would come from existing nuclear power plants, 12 percent would come from combined cycle natural gas (CC), solar would meet 9 percent, combustion turbine natural gas (CT) plants—which are mostly used to meet peak electricity demand—

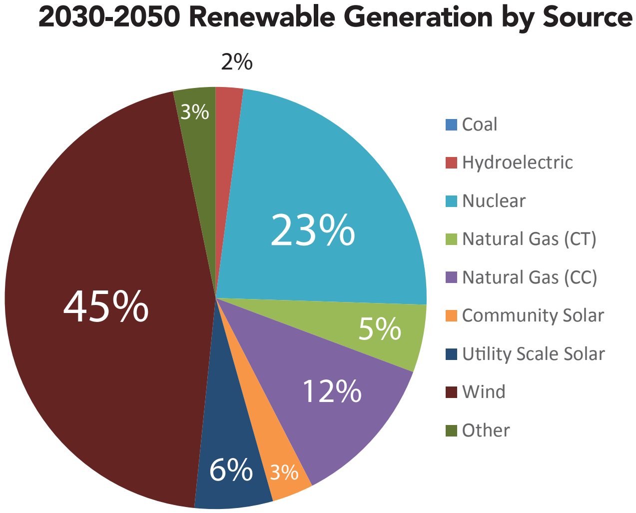


Figure 1. Seventy-nine percent of electricity under this scenario would come from sources that do not emit carbon dioxide.

would generate 5 percent of electricity, 2 percent would come from hydro, and "other" would constitute the remaining 3 percent of generation.[16]

This generation mix holds constant throughout the Renewable scenario by relicensing existing nuclear plants for an additional 20-year period, replacing or repowering wind turbines after they have reached the end of their 20-year useful lifetimes, and building and maintaining all of the proposed Community Solar installations in the project queue as of December 2018.[17, 18, 19]

The percentage of carbon-dioxide-free electricity in this portfolio falls substantially if Minnesota's existing nuclear power plants are closed. This would cause the percentage of carbon-dioxide-free electricity in the Renewable scenario to fall from 79 percent to 56 percent. The impact this would have on total emissions is demonstrated in Figure 15 and Figure 16.

Short-Term Nuclear scenario. The Short-Term Nuclear scenario describes how building new nuclear power plants would achieve 77 percent carbon-dioxide-free electricity by 2030, increasing to 80 percent by 2050.

As shown in Figure 2, coal-fired power plants would be replaced with nuclear power plants. Existing wind facilities would continue to operate until they reach the end of their useful lives, and new nuclear plants would be brought online to increase the share of zero-carbon-dioxide electricity on the grid as wind turbines are decommissioned. Existing Community Solar contracts are honored for their 25-year duration, but projects in the queue are not brought online due to their high cost.

By 2050, the Short-Term Nuclear scenario would be 80 percent carbon-dioxide-free. Nuclear would provide 78 percent of generation, 16 percent would be supplied by combined cycle natural gas, 1 percent would be supplied by combustion turbine natural gas, 2 percent would be supplied by hydroelectric, and 2 percent would be supplied by "other."

It is important to understand that nuclear power plants operate much longer than wind turbines. Nuclear power plants are initially licensed for 40 years, and they can be relicensed in 20-year increments thereafter, as Xcel Energy has done with its Minnesota nuclear plants.[20] The Nuclear Regulatory Commission is currently considering extending the licenses of multiple reactors in the U.S. to operate for 80 years.[21]

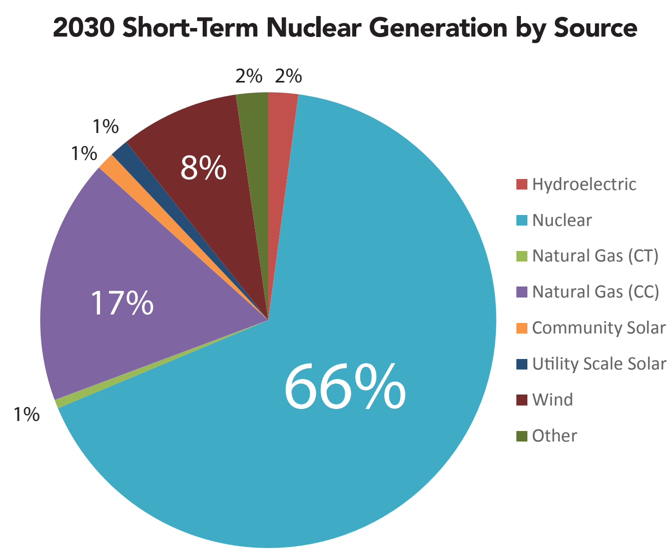


Figure 2. Two new nuclear power plants are built in 2026 and 2029, and by 2030 they generate 66.3 percent of the electricity in Minnesota. Wind generates 8.4 percent of electricity, solar 2.6 percent, combined cycle natural gas generates 17 percent, and the remainder is combustion turbine natural gas, hydroelectric, and other.

2050 Short-Term Nuclear Generation by Source

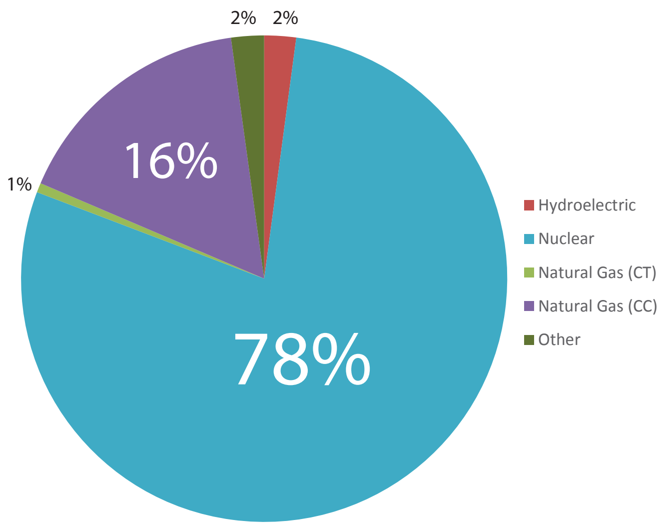


Figure 3. Nuclear power accounts for 78 percent of generation by 2050 as wind and solar go offline.

This means a nuclear power plant completed in 2026 would be initially licensed to operate until 2066, with a potential retirement date of 2106. In contrast, a wind turbine completed in 2026 will likely need to be repowered or scrapped by 2046.

Long-Term Nuclear scenario. The Long-Term Nuclear scenario examines the cost and impact on carbon dioxide emissions of gradually replacing existing coal, natural gas, wind, and solar resources with nuclear power plants as they reach the end of their useful lifetimes.

Under the Long-Term Nuclear scenario, 46 percent of electricity generation would be carbon-dioxide-free by 2030, with 33 percent coming from nuclear, 8 percent from wind, 2 percent from solar, and 2 percent from hydroelectric. The remaining electricity generation would be provided by combined cycle natural gas with 27 percent, coal with 22 percent, 2 percent combustion turbine natural gas, and 2 percent "other" (See Figure 4).

By 2050, the Long-Term Nuclear scenario would be 80 percent carbon-dioxide-free, with nuclear providing 78 percent of generation, 16 percent would be supplied by combined cycle gas, 1 percent would be supplied by combustion turbine natural gas, 2 percent would be supplied by hydroelectric, and 2 percent would be supplied by "other" (See Figure 5).

Again, it is important to stress the longevity of nuclear power plants. The long useful lifetime of nuclear power plants means the plants built in 2030 would be initially licensed to run until 2070, with a potential retirement date of 2110. Like all power plants, nuclear plants become less expensive to operate over time because they "pay down their mortgages," thus allowing them to produce electricity at a lower cost than when they are first constructed (See Figure 6).

ACE scenario. The ACE scenario examines the costs of complying with the proposed Affordable Clean Energy rule promulgated by the U.S. Environmental Protection Agency and repealing Minnesota's renewable energy mandate. ACE was promulgated to replace the Clean Power Plan, which was stayed by the U.S. Supreme Court and never implemented. ACE requires coal-fired power plants to make efficiency improvements that would reduce emissions of carbon dioxide and pollutants such as sulfur dioxide, nitrous oxide, and particulate matter.[23]

Under the ACE scenario, 36 percent of electricity generation would be carbon-dioxide-free by 2030, with 23 percent coming from nuclear, 9 percent

2030 Long-Term Nuclear Generation by Source

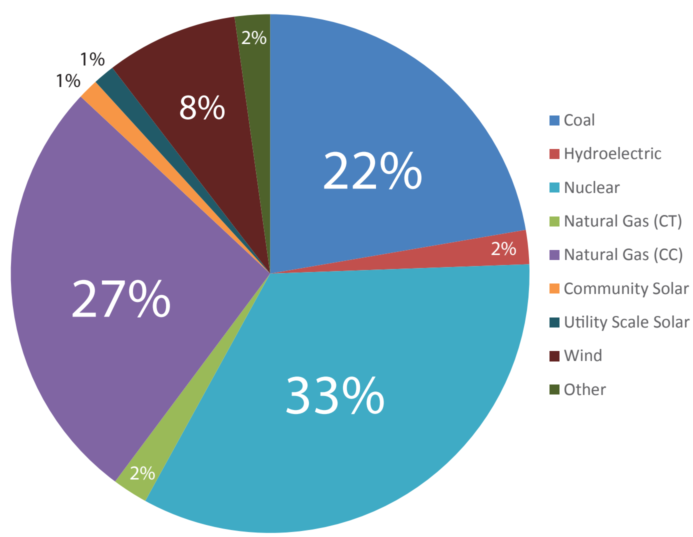


Figure 4. Nuclear accounts for 33 percent of power generation as nuclear plants are built after the retirement of two coal-fired power plants—Sherburne County Unit 1 and Unit 2 in 2026 and 2023, respectively.

2050 Long-Term Nuclear Generation by Source

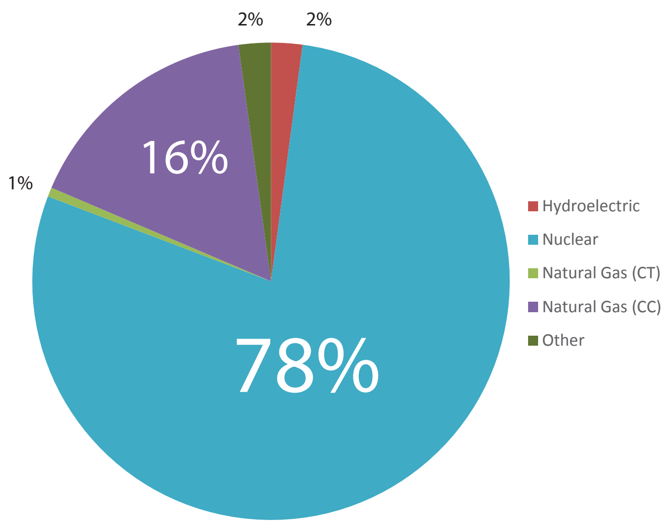


Figure 5. Nuclear power accounts for 78 percent of generation in 2050 as the Clay Boswell coal-fired power plant in Northern Minnesota is retired and replaced with nuclear capacity.

from existing wind, 2 percent from solar, and 2 percent from hydroelectric (See Figure 7). The remaining electricity generation would be provided by combined cycle natural gas with 18 percent, coal with 42 percent, 1 percent combustion turbine natural gas, and 3 percent "other."

By 2050, coal would account for 43 percent of power generation, combined cycle natural gas would account for 28 percent, nuclear would account for 23 percent, hydroelectric would account for 2 percent, combustion turbine natural gas would account for 1 percent, and 3 percent would be provided by "other." Wind and solar would no longer be part of the generation mix because the wind turbines will have reached the end of their 20-year useful lives and the 25-year contracts for Community Solar installations will have expired.

Coal-fired power plants, like nuclear power plants, have long useful lifetimes, allowing them to "pay off their mortgages" and produce affordable, reliable energy (See Figure 8).

Minnesota law currently prohibits the construction of new coal plants. Under the ACE scenario, the useful lifetimes of Minnesota's existing coal fleet, including Sherburne County Unit 1 and Unit 2, would be extended by implementing cost-effective efficiency improvements that are permissible under the ACE rule.[25]

Levelized Cost of Energy From Nuclear in 2012 $/MWh By Plant Age: 30 Year Outlook

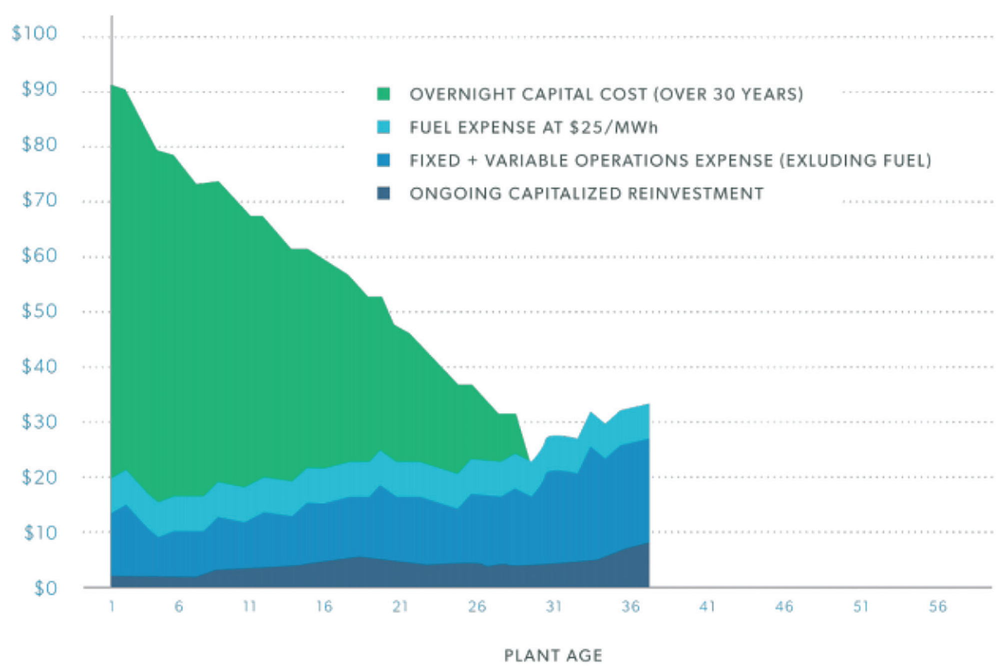


Figure 6. Power plants are able to generate electricity more affordably over time because they "pay down their mortgage;" thus, allowing them to reduce their costs.[22] This is especially beneficial for nuclear plants, which have useful lifetimes of 60 to 80 years.

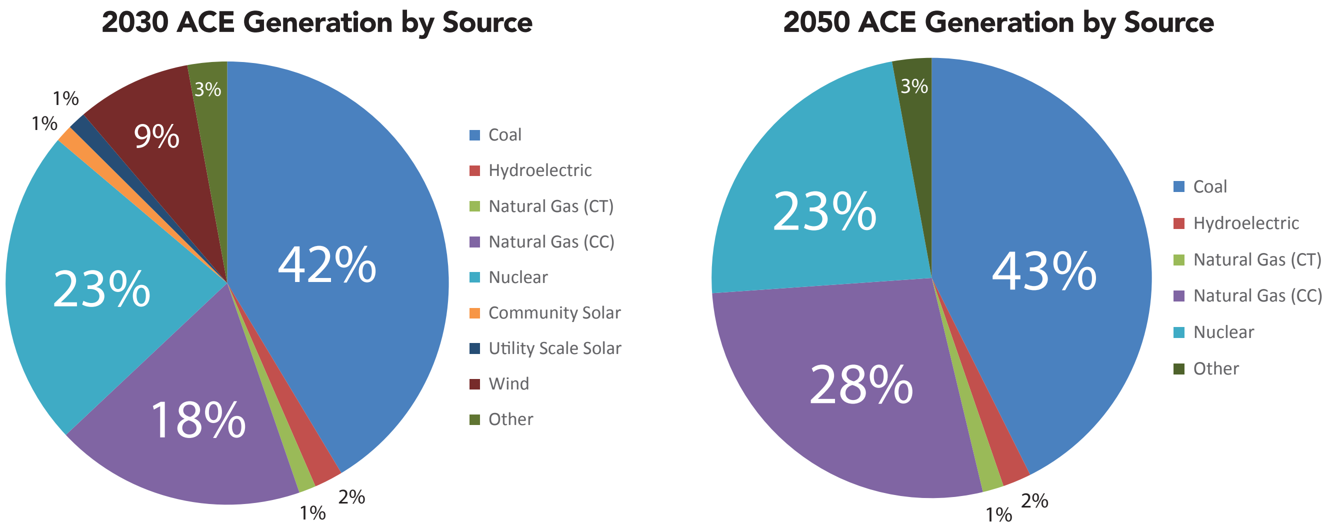


Figure 7. The ACE scenario is based upon the principle that Minnesota should utilize its existing generation sources for as long as practical. This means Minnesota's existing coal, nuclear, natural gas, wind, and solar installations are used until they reach the end of their useful lives.

Comparing Costs

The Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios would all come at considerable cost to Minnesota families and businesses. In contrast, the ACE scenario would reduce costs for consumers.

Figure 9 shows the additional costs of each scenario through 2030 and through 2050, relative to 2016 costs. The Renewable scenario dwarfs the costs of both nuclear scenarios, increasing electricity costs by $24.6 billion through 2030 and $80.2 billion through 2050. The Short-Term Nuclear scenario would increase electricity costs $9.5 billion through 2030 and $58.2 billion through 2050, and the Long-Term Nuclear scenario would increase electricity costs $2.7 billion through 2030 and $27.7

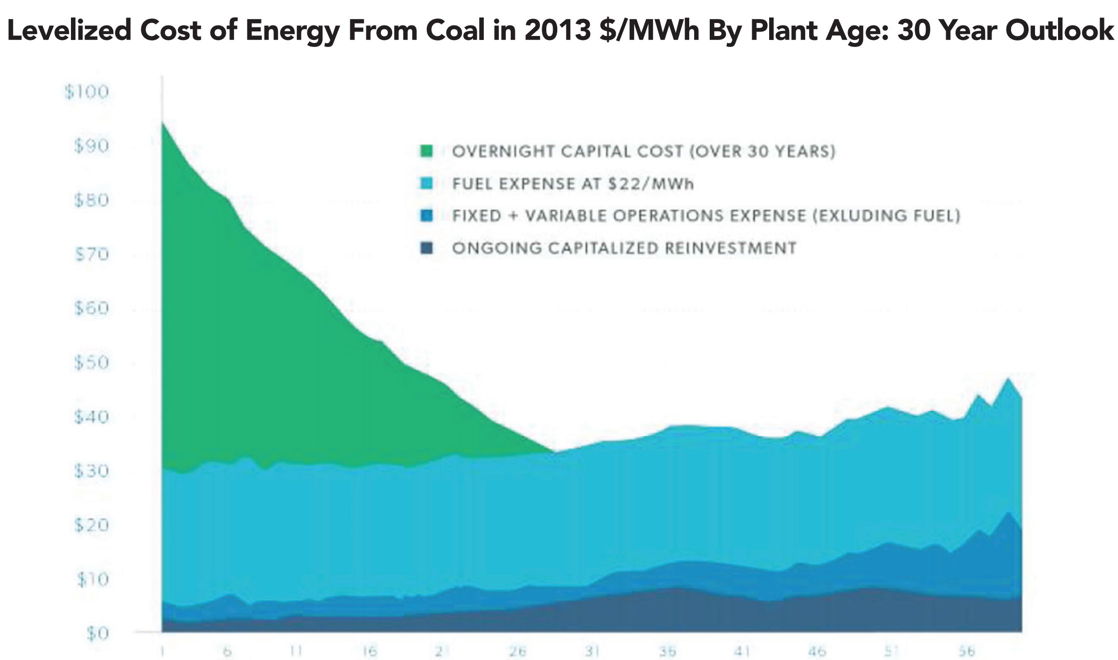


Figure 8. After the capital cost ("mortgage") is paid off in 30 years, the price of electricity from coal-fired power plants is largely dependent on the cost of fuel.[24]

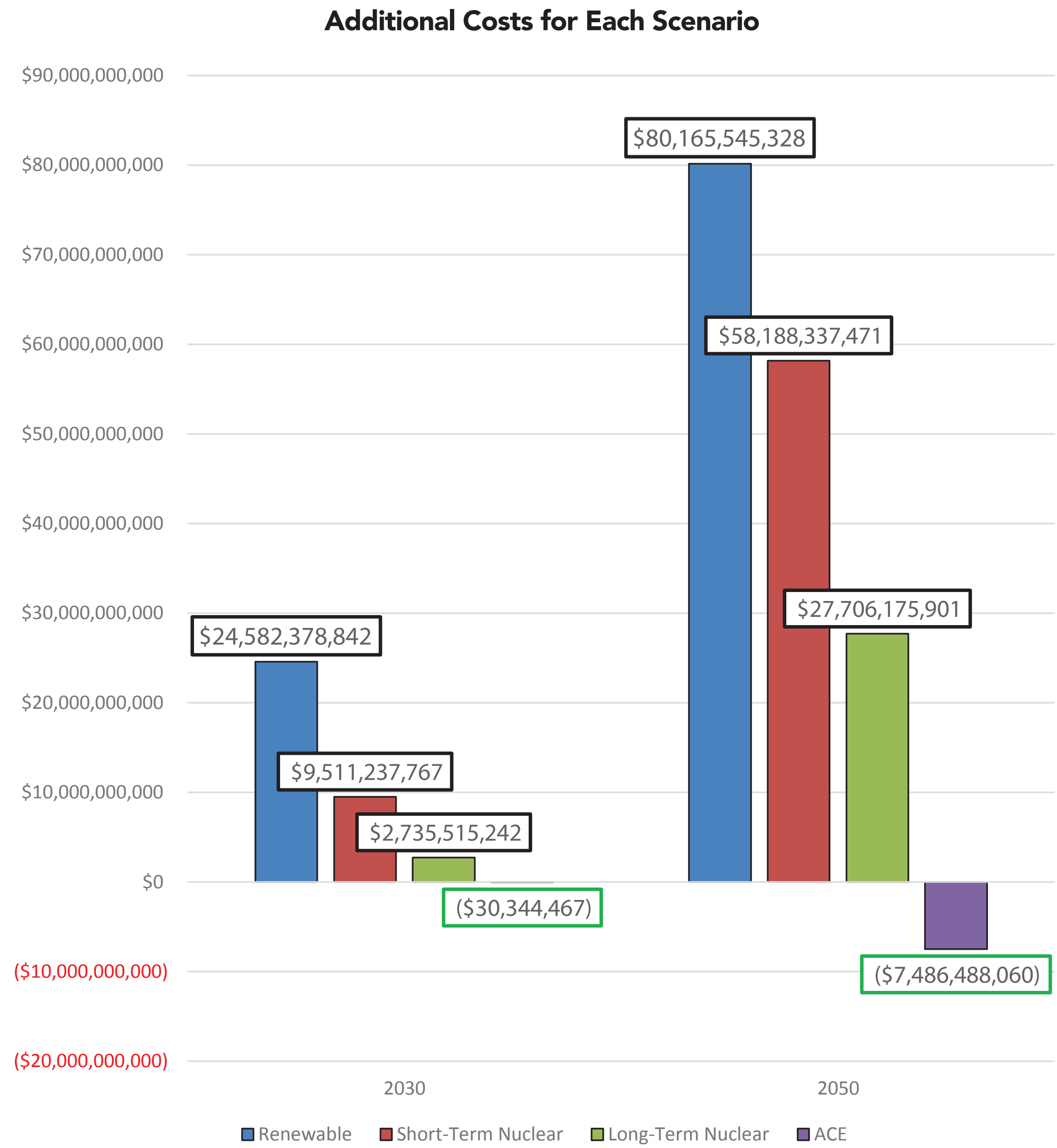


Figure 9. The Renewable scenario is the most expensive energy scenario, followed by the Short-Term Nuclear, Long-Term Nuclear, and ACE scenario.

billion through 2050. The ACE scenario would *lower* electricity costs $30.3 million by 2030 and $7.5 billion by 2050.

Total electricity costs are affected by four main components: generation, transmission, property taxes, and utility profits. Each is described below. Readers will likely be most familiar with the cost of generation, but transmission expenses, property taxes, and utility profits constitute a significant portion of the total cost of the electricity system.

For example, Figure 10 shows transmission, property taxes, and utility profits would constitute 41 percent of the total system cost of electricity in the Renewable scenario in the year 2030, while generation would comprise the remaining 59 percent.

The cost of each of these components is higher in the Renewable scenario than in either nuclear scenario or the ACE scenario.

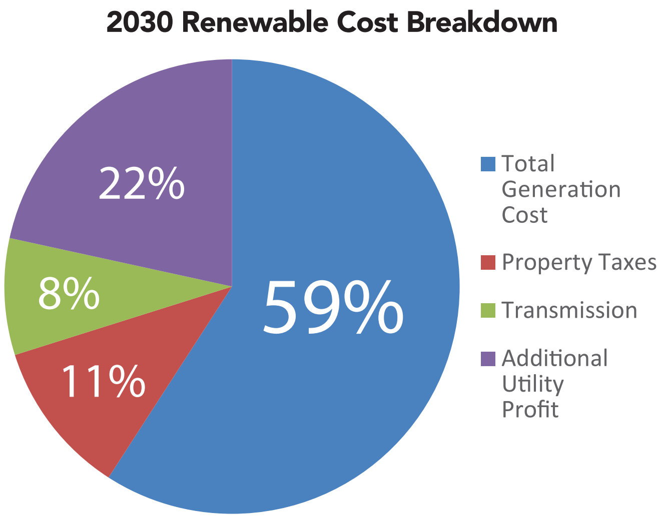


Figure 10. Utility profits, property taxes, and transmission are important, but seldom discussed, costs associated with integrating wind and solar on to the electric grid.

Generation Costs

Generation costs were calculated using a Levelized Cost of Energy (LCOE) assessment to determine the cost of generating electricity from different kinds of power plants while taking into account factors that are specific to Minnesota, such as capacity factors and delivered fuel costs.

Generation costs also account for the need to "overbuild" the grid to ensure electric companies can "balance the load." Essentially, this means electric companies must build natural gas power plants to provide reliable electricity to families and businesses when the wind is not blowing or the sun is not shining. These concepts and cost estimates are explained in greater detail in Appendix I.

Additional generation costs for the Renewable scenario exceed $40 billion through 2050, whereas additional generation costs for the Short-Term Nuclear scenario are $24.82 billion and the Long-Term Nuclear scenario costs an additional $9.72 billion, relative to 2016 prices. In contrast, the ACE scenario would save $6.45 billion in generation costs by 2050 compared to 2016 costs (See Figure 11).

High generation costs for the Renewable scenario stem primarily from needing backup generation when wind and solar are not producing electricity. Because the electricity grid is not a storage device, the supply of electricity on the grid must be perfectly matched to meet demand. If renewables are generating large quantities of electricity, natural gas must back down and vice versa. The result is a growing amount of idle capacity connected to, but

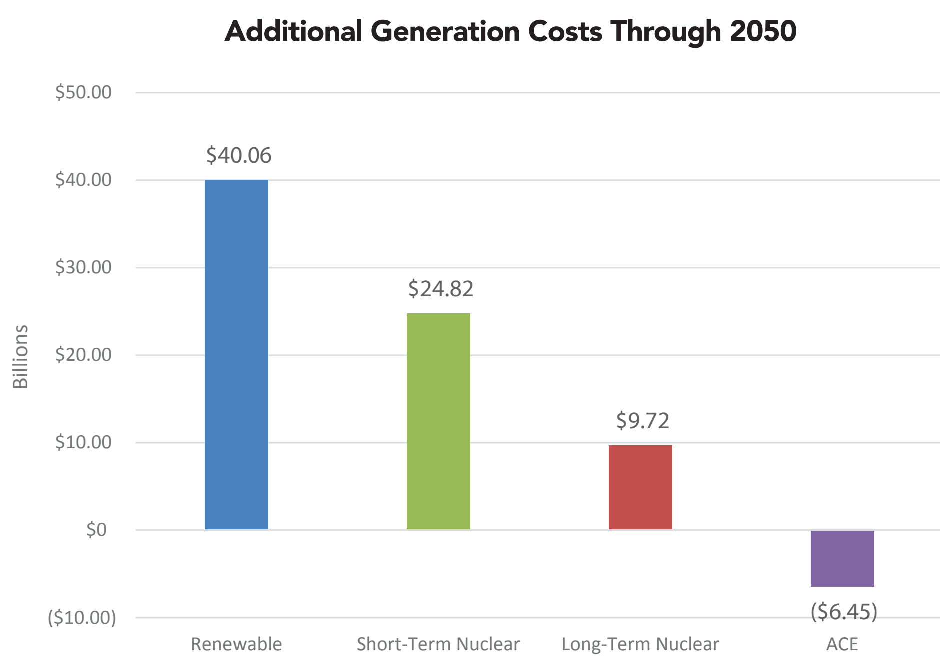


Figure 11. Additional generation costs for the Renewable scenario far exceed those of either nuclear scenario or the ACE scenario.

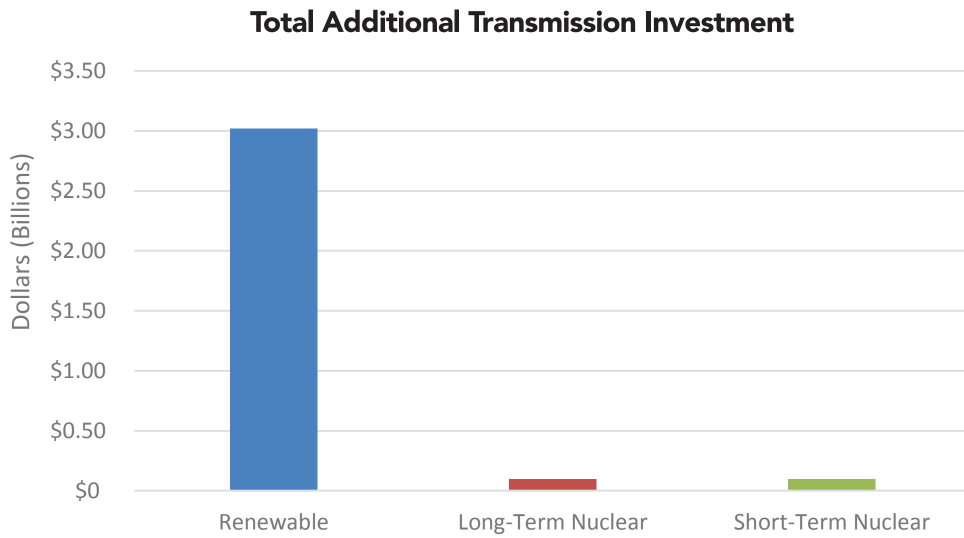


Figure 12. Transmission costs are much higher under the Renewable scenario than under the nuclear scenarios because more miles of transmission lines will be needed.

not supplying power to, the grid. Ratepayers must pay for this idle capacity.

In this way, intermittent renewable energy sources require Minnesotans to pay twice for electricity they can only use once.

Transmission

Transmission costs are important: Electricity generated does no good if it cannot be transported to the families and businesses who rely upon it. Our analysis found the Renewable scenario would cause transmission costs to increase by slightly more than $3 billion compared to 2016 costs. Both nuclear scenarios would cause transmission costs to increase by $100.4 million, whereas the ACE scenario would have minimal additional transmission costs because these power plants and transmission systems have already been built (See Figure 12).[26]

Transmission costs are higher under the Renewable scenario because wind turbines, and to a lesser extent solar installations, are frequently built far away from the areas where the electricity will be used by customers. High-voltage transmission lines routinely cost $1 million per mile.[27]

Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy are planning to build or purchase at least 1,846 megawatts (MW) of wind power from North and South Dakota.[28] This is a large amount of wind capacity, the equivalent of half of all the wind turbines installed in Minnesota.[29] Hundreds of miles of transmission lines must be built, and maintained, to transport this electricity to population centers in the Twin Cities Metro area.

Another additional cost resulting from adding wind and solar to the grid is upgrading existing transmission infrastructure to accommodate intermittent generation. This cost is substantial.

The electric grid was originally built to deliver steady, reliable power from dispatchable coal, natural gas, and nuclear power plants that provide predictable electricity. To transmit renewable electricity generation across vast distances without significant transmission losses, major upgrades such as high-voltage transmission systems must be added to the grid.[30] Additional technology is needed to manage the inconsistent power flows that are characteristic of intermittent energy sources like wind and solar.

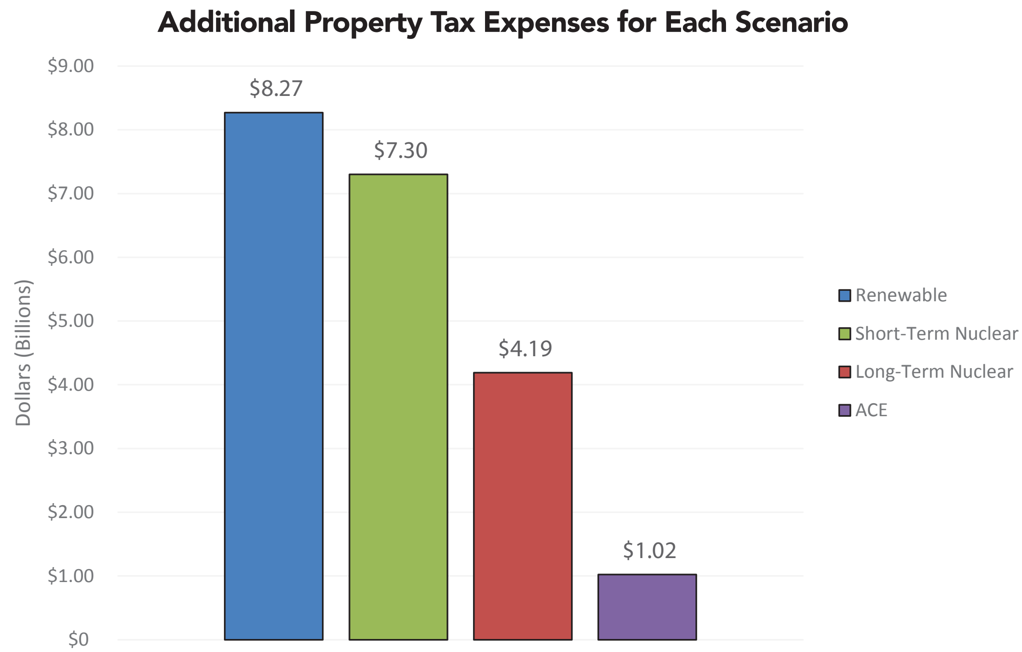


Figure 13. Property taxes increase most in the Renewable scenario because there will be more power plants and transmission lines will be needed to accommodate intermittent renewable energy sources.

Nuclear power, in contrast, can be located closer to population centers and therefore requires far fewer miles of transmission lines at significantly lower costs to consumers. While wind and solar would require an additional investment in transmission of $586,900 and $514,330 per MW, respectively, transmission costs for both nuclear scenarios were estimated to be an additional investment of $25,000 per MW. This cost is based on the transmission expenses from a nuclear plant under construction in the United States, the Vogtle nuclear plant.[31]

Transmission costs would be lowest under the ACE scenario because the transmission systems needed to transport electricity from existing coal plants already exist. Therefore, any transmission costs in the ACE scenario would be associated with maintaining existing infrastructure.

Property Taxes

Property taxes assessed on power plants are an important component of the cost of electricity. While they help raise revenue for the communities where power plants are located, they effectively increase the cost of producing and providing electricity. Property taxes on power plants are paid by all electricity consumers in the form of higher electricity prices.

Total property tax expenses for the Renewable scenario were $8.27 billion, $4.19 billion for the Long-Term Nuclear scenario, $7.30 billion for the Short-Term Nuclear scenario, and $1.02 billion for the ACE scenario (See Figure 13).[32]

Property tax payments for utilities were calculated to be 2 percent of the undepreciated cost of generation assets installed in each respective scenario, which is a midpoint of property tax expenditures for Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy.[33, 34, 35, 36]

Utility Profits

Because investor-owned utilities (IOUs) such as Xcel Energy, Minnesota Power, and Otter Tail Power, are regulated monopolies in Minnesota, they are not allowed to make a profit on the electricity they sell. Instead, they are guaranteed a profit when they spend money on capital assets such as power plants, transmission lines, and even new corporate offices.[37]

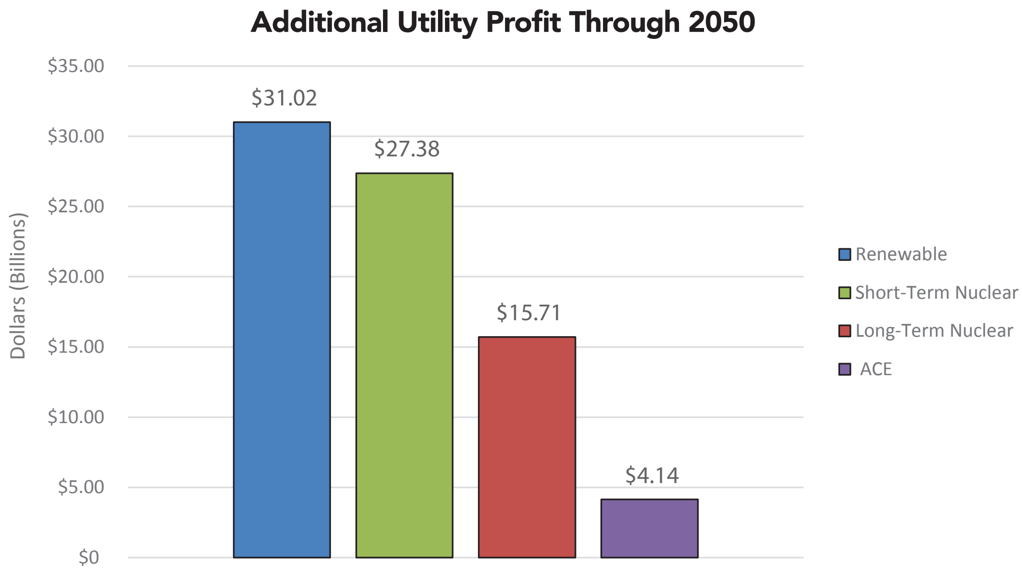


Figure 14. Utility profits would rise by $31.02 billion under the Renewable scenario, by far the most of any scenario.

The amount of profit a utility makes on these capital assets is called the Rate of Return (RoR) on the Rate Base. For the purposes of our study, we assumed this profit would be 7.5 percent on undepreciated capital because this is the current rate of return for Xcel Energy and Otter Tail Power.[38, 39]

Additional utility profits are highest under the Renewable scenario, reaching $31 billion through 2050 (See Figure 14). Profits for IOUs are $27.38 billion through 2050 under the Short-Term Nuclear scenario and $15.71 billion under the Long-Term Nuclear scenario. Utility profits are smallest under the ACE scenario, only $4.14 billion through 2050, because utility companies are not prematurely retiring resources that Minnesota families and businesses have already paid for and replacing them with new capital assets.

Utility profits are highest in the Renewable scenario because Minnesota must pay to build new wind and solar facilities and overbuild the grid to ensure reliability, increasing the amount of capital invested and raising profits.[40] This is why Xcel Energy has seen its profits increase by more than $25 million per year since 2007. That represents nearly a 40 percent increase between 2007—when Minnesota passed its first renewable energy mandate—and 2016.[41]

As noted earlier, wind turbines have a useful lifetime of only 20 years.[42] Therefore, utility profits would be bolstered under the Renewable scenario by the fact that more than 1,000 wind turbines would need to be routinely replaced at a current cost of more than $3.3 million per turbine.[43] Nuclear power plants, in contrast, have useful lifetimes of 40 to 80 years, reducing profits because new capital assets are not needed as often.

Emissions

While the Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios would impose significant yearly financial burdens on Minnesota households, they all would reduce carbon dioxide emissions from power plants. Emissions would eventually rise under the ACE plan as existing wind turbines reach the end of their useful lives (See Figure 15).

Carbon dioxide reductions in the Renewable scenario would be more gradual, declining steadily toward 5 million metric tons in 2030. However, as shown in Figure 15, achieving CO_2 reductions to this level is contingent upon the continued operation of Minnesota's two existing nuclear power plants, Monticello and Prairie Island. If these nuclear plants are closed, emissions would increase and the Renewable scenario would have

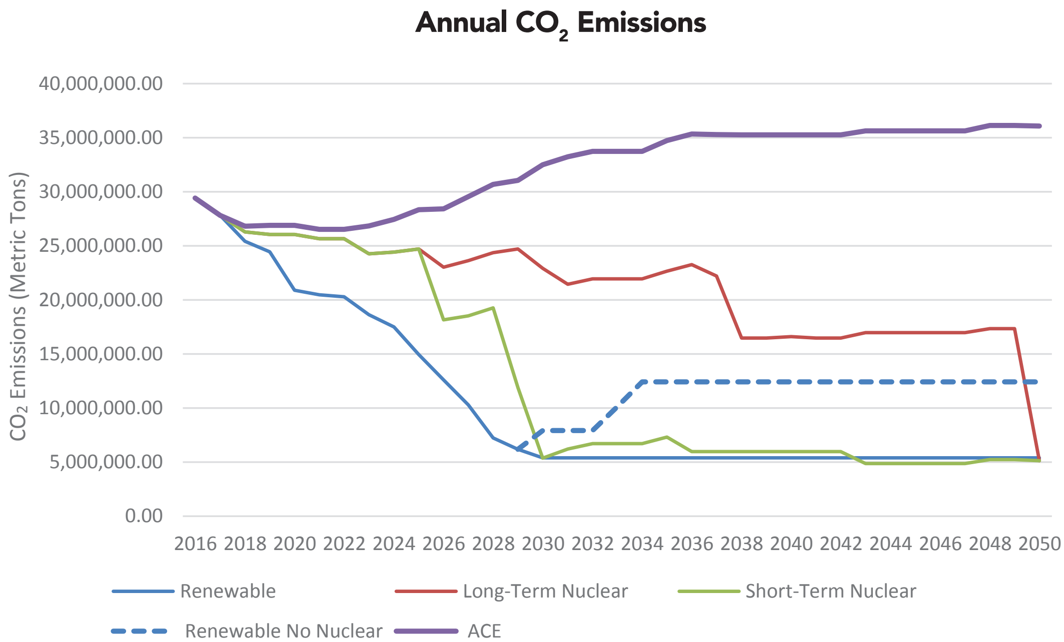


Figure 15. Carbon dioxide emissions would reach approximately 5 million metric tons in the Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios. Reductions come more quickly (by 2030) in the Renewable and Short-Term Nuclear scenarios because investment in wind and solar projects would likely be pursued in the next few years to capture as many federal subsidies as possible. Long-Term Nuclear achieves 5 million metric tons of emissions in 2050. Carbon dioxide emissions increase to 36 million metric tons per year under the ACE scenario.

higher CO_2 emissions than the Short-Term Nuclear scenario.

It is important to note that we did not attempt to quantify the significant CO_2 emissions associated with mining, manufacturing, and constructing wind turbines and solar panels. These emissions would be significant, because each 3.3 MW wind turbine requires 4.7 tons of copper, 335 tons of steel, 1,200 tons of concrete, 3 tons of aluminum, and 2 tons of rare earth metals. These metals are mined using diesel-powered mining equipment, smelted in coal-fired furnaces, transported by diesel-powered barges and trucks, and assembled using diesel-powered cranes.

Carbon dioxide reductions in the nuclear scenarios would begin later due to the longer lead times for building new nuclear power plants. After that, however, the carbon dioxide reductions would be more sudden, cost effective and, because nuclear plants have lifespans of 40 to 80 years, more permanent.

Government policies should be evaluated on their ability to maximize benefits while minimizing costs. Although overall CO_2 emissions are lowest in the Renewable scenario, Figure 17 shows the cost per metric ton of carbon dioxide averted would be significantly higher. Renewable energy is the least cost-effective way to reduce CO_2 emissions.

It is important to note that the cost of reducing CO_2 emissions in the Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios would far exceed the Social Cost of Carbon (SCC) values assigned by the Minnesota Public Utilities Commission, which range from $15.20 to $69.48 per short ton by 2050.[44] This means the Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios would each spend more money to avert carbon dioxide emissions than the anticipated economic damages of each marginal ton of carbon dioxide; thus, failing a proper cost-benefit analysis.

In contrast, the ACE scenario would save $45 for each additional ton of CO_2 emitted, relative to a 2016 baseline, by 2050. This means the benefits Minnesota would reap from affordable electricity

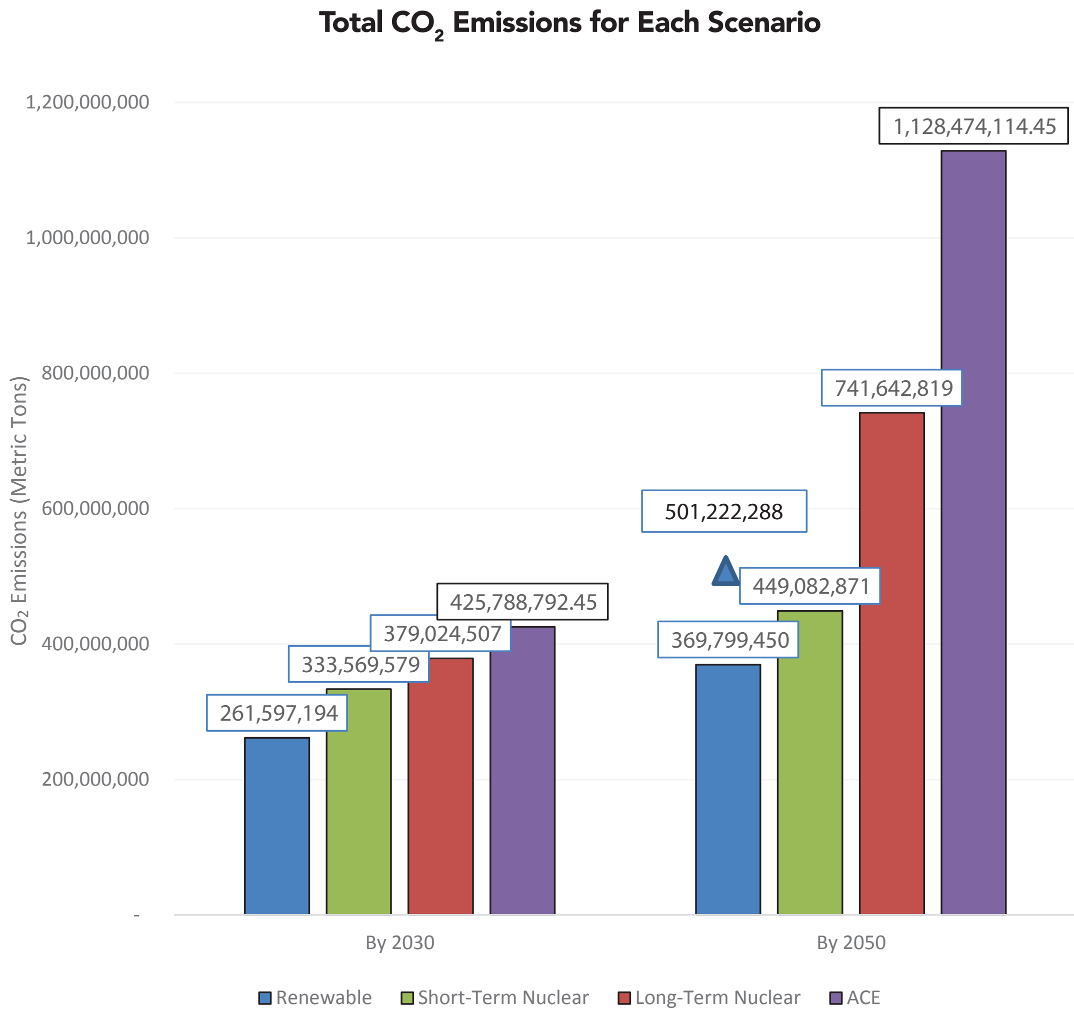


Figure 16. Cumulative carbon dioxide emissions for each scenario are shown above. The blue triangle depicts total CO_2 emissions in the Renewable scenario if existing nuclear plants are closed in Minnesota.

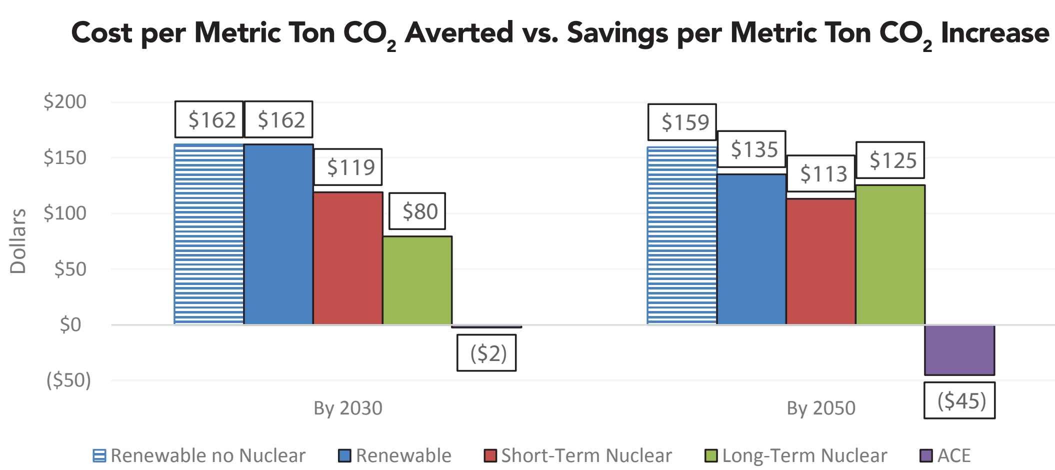


Figure 17. This figure shows the cost, or savings, per ton of CO_2 averted or added through 2030 and 2050, relative to a 2016 baseline.

could be nearly 300 percent more than the costs associated with the additional emissions.

Section II: High Energy Costs Harm Minnesota Families and the Economy

Cost to MN Households	Total Cost Through 2050	Annual Cost Through 2050
Renewable	$37,231	$1,200
Short-Term Nuclear	$26,862	$867
Long-Term Nuclear	$12,705	$410
ACE	($3,486)	($112.50)

Table 1. Each Minnesota household would spend an additional $1,200 per year under the Renewable scenario.

Renewable energy is often touted as a benefit for Minnesota's economy. But increasing the cost of electricity does not grow our economy, it simply transfers into the electricity sector money that would have been spent elsewhere in the economy.

The billions of dollars spent in the Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios would impose significant additional costs on each of Minnesota's 2.1 million households, whereas the ACE scenario would reduce household electricity costs (See Table 1). Average additional costs would be $1,200 per year for the Renewable scenario, $867 per year for the Short-Term Nuclear scenario, and $410 per year for the Long-Term Nuclear scenario. The ACE scenario would save each Minnesota household $112.50 per year through 2050.

The high costs of the Renewable and nuclear scenarios would increase the cost of electricity. Table 2 shows the average additional cost of electricity through 2050 for each scenario. The Renewable scenario would have the largest impact on rates increasing prices by 4.18 cents per kWh, the Short-Term Nuclear scenario would raise rates by 3.03 cents per kWh, and the Long-Term Nuclear scenario would raise rates by 1.45 cents per kWh. The ACE scenario would *cut* rates by 0.39 cents per kWh.

Enacting policies that will increase costs for each Minnesota household by $1,200 every year represents a massive opportunity cost for Minnesota families. Each household will have less money for rent or mortgage payments, healthy food for their families, braces for their children, college tuition, retirement, or a short weekend getaway.

Increasing the average household expenditure on electricity will also harm Minnesota's economy in two primary ways: It will reduce the amount of household income available for other goods and services, therefore reducing demand in other sectors of the economy, and it will also increase the costs of healthcare, education, food, and durable goods, as businesses attempt to recoup their own higher electricity expenses by raising prices.

Increasing electricity costs also affect the economy by affecting employment. Using the economic modeling software IMPLAN to calculate the impact of electricity costs on employment, we found these scenarios would destroy more jobs than they create. This is particularly true in the Renewable scenario, where prices increase the most and the vast majority of the jobs created are temporary construction jobs.

Scenario	Additional Cost Per kWh (cents)	Percent Increase
Renewable	4.18	40.2
Short-Term Nuclear	3.03	29.2
Long-Term Nuclear	1.45	13.9
ACE	(0.39)	(3.8)

Table 2. Electric rates increase by 40.2 percent relative to November 2018 prices of 10.38 cents per kWh in the Renewable scenario, 29.2 percent in the Short-Term Nuclear scenario, and 13.9 percent in the Long-Term Nuclear scenario. Under the ACE scenario, rates would fall 3.8 percent.

High electricity costs disproportionately jeopardize jobs in energy-intensive industries like agriculture, manufacturing, and mining. These industries compete in a global economy, and increasing electricity costs leave them at a competitive disadvantage to similar firms in other states and nations.

While these industries would be impacted most, all industries would be affected. We note below, for example, how rising electricity prices would cause school districts to have a more difficult time hiring and retaining teachers.

Additional Household Electricity Bill			
Scenario	Additional Monthly Cost	Additional Annual Cost	Percent Increase
Renewable	$31.24	$374.93	32.02
Short-Term Nuclear	$22.69	$272.33	23.26
Long-Term Nuclear	$10.80	$129.61	11.07
ACE	($2.92)	($35.10)	(3.00)

Table 3. This table shows the average Minnesota household can expect to pay $374.93 more every year under the Renewable scenario, $272.33 every year under the Short-Term Nuclear scenario, and $129.61 under the Long-Term Nuclear scenario. Each household would save $35.10 under the ACE scenario.[45, 46] Bills increase less than the percent increase in total electricity costs because residential electricity prices are 13.10 cents per kWh, while the average cost for all sectors is 10.38 cents.[47]

Impact on Electric Bills

Minnesota families already pay residential electricity rates that are above the national average, and three of the four scenarios would increase their electricity costs. Table 3 shows the impact Minnesota residents can expect to see on their electric bills under the four scenarios.

Rising electricity prices would impose economic hardship for everyone, but they would be disproportionately harmful for low-income and minority households. Seniors living on a fixed income may also struggle to cope with rising electricity costs under the Renewable and nuclear scenarios (See Figure 18).

In 2015, 31 percent of households in the U.S. reported facing challenges paying their energy bills or sustaining adequate heating and cooling in their homes. Approximately 20 percent of households reported reducing or forgoing necessities such as food or medicine to pay an energy bill.[48] These figures would surely increase if households lose $410 to $1,200 of their annual income to higher energy costs.

To bolster support for renewable energy and make it appear as if Minnesota electricity customers are getting a good value on their electric bills relative to their peers nationally, renewable energy advocates and Xcel Energy often claim that electricity bills in Minnesota are 22 percent below the national average.[49] These claims are often intentionally confusing, and Minnesota residents must listen carefully to the specific language of the claims to understand what they mean for their finances.

Residential electricity prices in Minnesota are higher than the national average, but because Minnesotans use less electricity than people living in 31 other states, our bills are lower.[50] Minnesotans use less electricity than the national average because 66 percent of households in our state use natural gas for heating, whereas in many areas of the country, including southern states, households use electricity as their primary heating fuel.[51] These households also use more electricity for air conditioning than people living in Minnesota.

Therefore, Minnesotans have lower electricity bills because we use less electricity than residents in other states, not because our electricity prices are lower.

Impacts on Employment

By reducing the income available for spending in other sectors of the economy, the Renewable, Short-Term Nuclear, and Long-Term Nuclear scenarios would reduce the ability of Minnesota families to pay for, thus reducing the demand for, other goods and services in the broader economy. This makes it more difficult for businesses to retain employees and raise wages. Most importantly, it

Household Energy Insecurity by Household Characteristics, 2015
Percent of Households

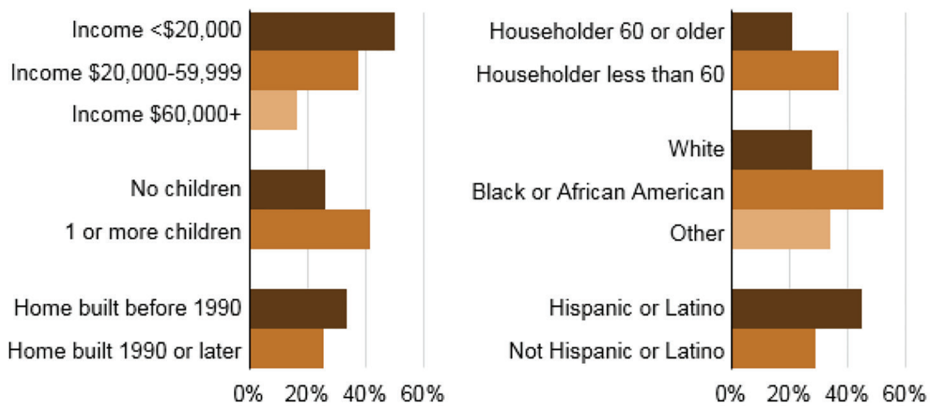


Figure 18. Nearly half of households surveyed earning less than $20,000 said they had trouble paying their energy bills. Nearly half of black Americans reported the same issue. Older houses are also less energy efficient, contributing to higher rates of energy insecurity for those living in older dwellings.

makes Minnesota businesses less competitive with companies in other states, or nations, with lower energy costs.

The ACE scenario, in contrast, would produce an increase in employment because it would reduce household energy costs, allowing Minnesota families to keep more of their money and spend it in other sectors of the economy.

Using the economic modeling software IMPLAN, we calculated the number of jobs that would be lost due to higher electricity prices in the Renewable and nuclear scenarios or gained due to lower electricity prices in the ACE scenario.

Table 4 shows the Renewable scenario would result in a loss of nearly 21,000 jobs by 2050, the Short-Term Nuclear would result in nearly 14,000 job losses, the Long-Term Nuclear would result in a loss of 6,745 jobs, and the ACE scenario would lead to a gain of 1,518 of jobs.

Scenario	Impact on Employment	Impact on Labor Income	Impact on GDP
Renewable	(20,946)	($1,075,313,814)	($3,109,356,980)
Short-Term Nuclear	(13,916)	($715,123,983)	($2,068,046,680)
Long-Term Nuclear	(6,745)	($347,157,183)	($1,003,553,360)
ACE	1,518	$80,883,529	$233,582,289

Table 4. The Renewable scenario would cause a loss in employment of nearly 21,000 jobs. The ACE scenario would result in an increase of approximately 1,500 jobs.

Furthermore, Minnesota's GDP would be $3.1 billion smaller (in 2019 constant dollars) every year through 2050 under the Renewable scenario, $2.1 billion smaller under the Short-Term Nuclear scenario, $1 billion smaller under the Long-Term Nuclear scenario, and $234 million larger under the ACE scenario.

While the initial building of new wind and solar projects does create a substantial number of temporary jobs, many more permanent jobs are lost due to the higher electricity prices that accompany renewable energy.

High Electricity Prices Destroy Jobs in Manufacturing, Mining, Agriculture, and Education

Energy-intensive industries such as manufacturing, mining, and farming are at the highest risk of becoming uncompetitive due to increasing electricity prices. Industrial electricity users consumed 22.3 billion kWh of electricity in 2017, nearly 32 percent of Minnesota's total electricity usage that year.[52] Increasing the cost of electricity by 4.18 cents per kWh would require Minnesota's industrial electricity consumers to spend an additional $931.7 million under the Renewable scenario. In contrast, industrial electricity users would save $87.1 million under the ACE scenario.

Manufacturing

Manufacturing is the single largest private-sector component of Minnesota's economy, accounting for $49.2 billion in annual economic activity, which constituted 16 percent of Minnesota's total GDP in 2017. Minnesota manufacturers employed 319,000 people in 2017, the equivalent of 13 percent of the state's private-sector workforce.[53]

Furthermore, manufacturing jobs were some of the highest-paying jobs in the state, with average annual wages exceeding $65,000. These wages are 16 percent higher than the annual average wage for all industries.[54] These high wages are why each manufacturing job supports 1.9 indirect and induced jobs in other sectors of the economy, bringing the total employment impact of manufacturing to more than 1 million jobs.[55]

Unfortunately, these jobs are at risk of moving elsewhere if we experience rising electricity prices, and these risks are highest if lawmakers pass a 50 percent renewable energy mandate.

For example, in 2015, California enacted a 50 percent renewable energy mandate by 2030. Since the passage of this law, the Golden State has seen its industrial electricity prices increase to nearly twice the national average. During this time, the number of manufacturing jobs in California increased by just 5 percent since 2010, while the number of manufacturing jobs in the rest of the country increased by 11.7 percent (See Figure 19).[56]

Manufacturing is the bedrock of many Minnesota communities, and this sector has long been an

California Manufacturing Job Growth Continues to Lag the Country

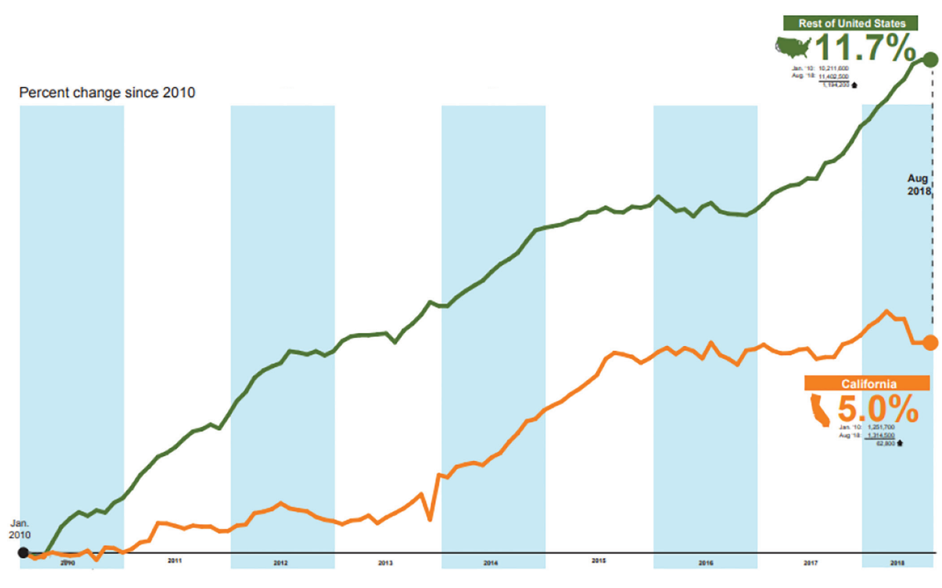


Figure 19. This figure shows manufacturing growth from 2010 through 2018. Manufacturing job growth in California generally followed the national average prior to 2015, when the state implemented its 50 percent renewable energy mandate. Since that time, job growth for the manufacturing sector has significantly lagged the national average.

important pathway to the American middle class, allowing individuals without a four-year degree to earn family-supporting wages and achieve the American Dream.

Fewer opportunities in the manufacturing sector are especially devastating to small, rural communities. Because manufacturing has a high multiplier effect, a factory closing down in Greater Minnesota has a large, negative ripple effect throughout the entire community.[57]

Unfortunately, Minnesota's proposed renewable energy mandates would cause electricity prices to increase 40.2 percent in the coming years, resulting in fewer opportunities in the manufacturing sector.

Mining

Like manufacturing, mining is an indispensible pillar of Minnesota's economy. With annual average wages exceeding $80,000, mining jobs are some of the best jobs in the entire state, but they are especially critical for northeastern Minnesota, where average annual wages are approximately $42,000 (See Figure 20).[58]

Unfortunately, high electricity prices threaten these high-paying jobs because mining operations use enormous quantities of electricity. The cost of electricity constitutes roughly 25 percent of the cost of iron ore produced in Minnesota. The cost of electricity for Minnesota's iron mines has already increased more than 60 percent on average since 2007, when Minnesota enacted its 25 percent renewable energy mandate.[59]

Doubling down on this misguided policy would seriously jeopardize Minnesota's mining and paper mill industries. Iron ore mines and paper mills in northern Minnesota used 4.77 billion kWh of electricity in 2016, which was 8 percent of the electricity used in the entire state. This figure could reach 6.1 billion kWh if iron mines operate at a higher capacity.[60]

By increasing electricity prices by 4.18 cents per kWh, a 50 percent renewable energy mandate would increase the cost of electricity for the mining and paper mill industries between $199.2 million and $258.8 million every year. This is the equivalent of 2,490 to 3,185 high-paying mining jobs. Minnesota policymakers need to understand that their actions are actively undermining industries

Wages for Mining Jobs and All Jobs, Minnesota and Selected Counties, 2015

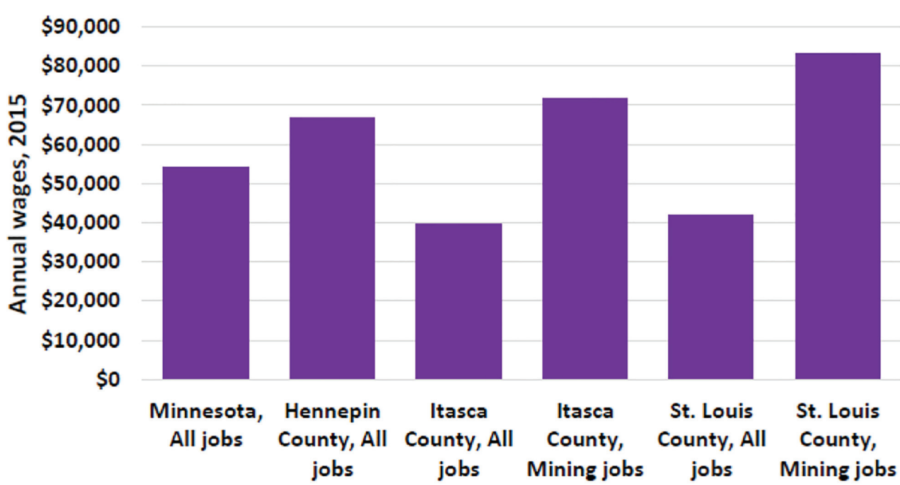


Figure 20. This graph compares the average income for jobs in Hennepin County, Itasca County, St. Louis County, and an average of all Minnesota counties. Average incomes in Hennepin County are approximately $66,600—far greater than the average income for non-mining jobs in northern Minnesota, where wages are nearly $12,000 lower than the state average.

that are crucial to our state's economy and our nation's security.

Under the ACE scenario, iron mines and paper mills would save between $18.6 million and $23.8 million, on average, every year through 2050 relative to 2016 prices. This means the gulf between the Renewable scenario and the ACE scenario is $217.9 million and $278.6 million, the equivalent of 2,723 to 3,482 mining jobs.

Mining is a competitive global industry. Such large increases in electricity prices clearly jeopardize Minnesota's present mining industry, but they also threaten the industry's future. If iron mines in Minnesota close, or potential mining operations such as proposed copper, nickel, titanium, and manganese mines fail to open, it will be economically devastating to northern Minnesota.

In August 2018, American Experiment released a study that found developing Minnesota's copper, nickel, platinum, and titanium deposits would boost our economy by $3.7 billion every year and support a total of 8,500 jobs throughout the state. This enormous boost to Minnesota's economy is far less likely to occur if we increase electricity prices and price ourselves out of global commodities markets.[61]

Not only would high electricity prices harm the Minnesota economy, they will also make the U.S. more dependent on foreign countries for the metals and minerals we use every day. Almost always, these nations have fewer protections for workers and the environment, and they likely use mining techniques that are less efficient and have a higher carbon footprint. This raises an important question: Are Minnesota's electricity-price-increasing policies a net-positive for the planet as a whole, or are we simply exporting to developing nations and amplifying negative environmental impacts that make the planet worse off?

Agriculture

Rising electricity prices will negatively impact Minnesota agriculture because electricity is a significant expense for farmers and food manufacturers. Electricity is used at livestock operations for heating and cooling, milking, heating water tanks, and powering barn cleaners, and crop farmers use electricity for irrigation and grain drying, among many other uses.

Among livestock producers, poultry production has the highest share of electricity expenses at nearly 5 percent, while hog production has the highest average electricity expense at $16,936 per year.[62]

This is problematic for Minnesota, which is the largest producer of turkeys in the United States, the 11th-largest producer of laying hens, and the third-largest producer of hogs.[63] On average, hog farmers could expect to see their electricity costs increase 40.2 percent, or an additional $6,800 per year, under the Renewable scenario. The ACE scenario would save these farmers $508 per year. While higher electricity prices would increase costs for all Minnesota farmers, it is important to note energy costs constitute a larger share of expenses for small farms than they do for medium or larger farms.[64] Rising electricity prices would have significant negative effects because 55 percent of Minnesota farms sell less than $50,000 in products, according to USDA data.[65]

The cost of rising electricity prices can be estimated using a farm energy calculator developed by Freeborn-Mower Cooperative Services in Albert Lea, Minnesota, which provides the estimated electricity consumption for various farm activities.[66]

Consider the impact of higher electricity prices on a small dairy farm in Minnesota milking 40 cows that also produces its own grain. This farmer could expect to see his costs for milk cooling, milking machines, watering cows, barn ventilation, lighting, and manure handling increase by more than $520 for electricity in the Renewable scenario.

These costs would be dwarfed by the cost of electricity used for grain drying. In 2017, the average corn yield in Minnesota was 194 bushels per acre.[67] Assuming 250 acres of corn were planted, a small acreage in the broad scheme of modern farms, the yield would be approximately 48,500 bushels. It takes 1 kWh to dry a bushel of grain with a fan without an electric heater, and 2 kWh per bushel with electric heat.

This means the 4.18 cents per kWh increase in electricity prices due to the renewable energy mandate would increase the cost of drying grain between $2,025 and $4,050 if the farmer continued to use electricity.[68] This would potentially increase the total annual cost borne by the farmer under the Renewable scenario by approximately $2,545 to $4,570. Increasing costs by 5 to 10 percent of total farm sales for the same electricity service is a substantial and unreasonable financial burden to place on farmers in the face of fluctuating commodity prices. The ACE scenario would save this farmer $238 to $461 per year.

Renewable energy advocates often claim wind and solar will increase revenues for farmers by generating lease payments when wind turbines and solar panels are built on their land. While this is likely true for some farmers, others will become less competitive as a result of higher electricity costs. Furthermore, lease payments will not help Minnesota farmers if utility companies continue to heavily invest in North Dakota and South Dakota wind projects.

More Money on Electricity Means Less Money for Teachers

U.S. school districts spend $6 billion each year on energy, making it the second largest expense for schools after the salaries of teachers, administrators, and support staff. Every extra dollar spent on electricity is one less dollar that could be spent on improving the education of children.[69]

Schools can take steps to reduce their electricity consumption, such as shutting down computers when they are not in use and switching to energy-efficient light bulbs. But the easy and affordable means of reducing electricity consumption are quickly exhausted, especially when electricity costs continue to increase for school districts already struggling to make ends meet.

Take the Minneapolis Public Schools (MPS) district, for example, which sought a $30 million tax increase in the November 2018 midterm elections to cover budget shortfalls.[70] According to 2017 electricity benchmarking data collected by the City of Minneapolis, 55 schools in MPS purchased 45 million kWh of electricity from the grid. Increasing electricity prices by 4.18 cents per kilowatt hour would increase their electricity expenditures by $1.87 million, the equivalent of 33 teachers making $56,000 per year.[71] The ACE scenario would allow MPS schools to hire 3 more teachers.

Edina Public Schools district uses 13.8 million kWh of electricity every year.[72] Increasing the price of electricity by 4.18 cents per kWh would result in increased electricity costs of approximately $576,400. Edina would have to lay off 10 teachers making $56,000 per year to pay these higher electric bills, or raise property taxes to keep them on staff.[73] In contrast, the ACE scenario would allow them to hire one additional teacher earning $50,000 per year.

Lastly, higher electricity prices would harm rural school districts in Greater Minnesota to a greater degree because these areas are already facing teacher shortages.[74] Starting salaries for licensed teachers in some rural areas are as low as $31,000 per year, a key reason why rural districts are unable to compete for teachers with more affluent urban and suburban districts. One of the most effective means rural school districts have to address teacher shortages is to increase wages in an attempt to lure teachers, but increasing electricity prices will limit their ability to do so.

High electricity prices represent a very real opportunity cost for school districts, forcing them to spend money on electric bills that should be spent on students. Enacting a 50 percent renewable energy mandate would sacrifice investments in education for no meaningful environmental benefits, whereas the ACE scenario would allow schools to put more teachers in the classroom, building a brighter future for Minnesota children.

Renewable Energy Jobs are Temporary Construction Jobs

Renewable energy advocates often tout renewable energy as a major engine of job creation. They fail to mention that most of the jobs created by the wind and solar industry are temporary construction jobs that go away once the project is finished.

According to the 2018 U.S. Energy and Employment Report, electric power generation accounted for 12,010 jobs in Minnesota during 2017, with solar and wind accounting for 4,016 and 2,088 jobs, respectively.[75] Together, wind and solar constituted 6,104 jobs in the power generation sector (See Figure 21).

Of the 12,010 jobs created by the electric power generation sector, 5,151, or 42.9 percent, were temporary construction jobs (See Figure 22).[76]

Because there were no natural gas, coal, or nuclear plants under construction in Minnesota and Minnesota Department of Commerce data show 467 MW of solar was added in 2017, it is reasonable to assume most of these temporary jobs are attributable to solar and wind.[77, 78] Subtracting the total number of wind and solar jobs from the number of temporary construction jobs results in just 953 non-construction jobs in the wind and solar industry, meaning 82 percent of wind and solar jobs are temporary.

Furthermore, the point of the electricity sector is to create *electricity*, not jobs. Although wind and solar constituted nearly 51 percent of the jobs in the

Electric Power Generation Employment by Detailed Technology Application

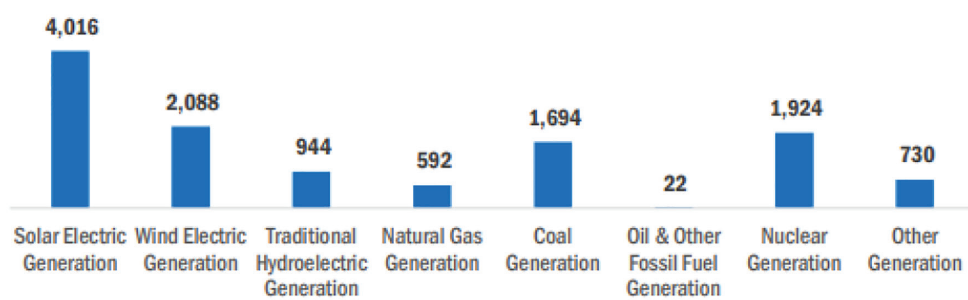


Figure 21. There were 12,010 jobs in the electric power sector in Minnesota during 2017, with solar and wind jobs accounting for approximately half of these jobs.

Electric Power Generation Employment by Sector

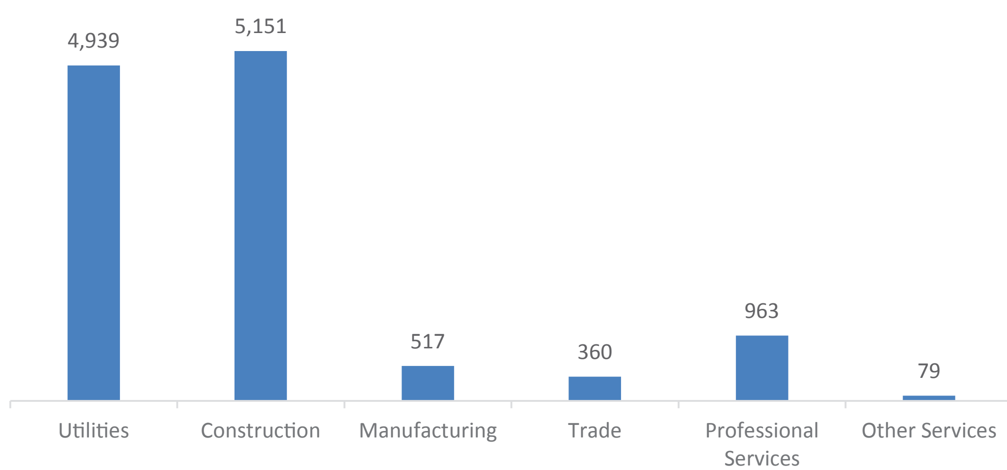


Figure 22. Many of the jobs in the electric power sector were construction jobs. Because no conventional sources of electricity were under construction during this time, it is reasonable to assume the employment in construction was due to installations of wind and solar facilities.

electric generation sector in 2017, they produced just 20 percent of the electricity, meaning the jobs created by building renewable energy systems are a poor value for Minnesota families.

Section III: Will Renewable Energy Improve the Environment?

Renewable energy enthusiasts often portray wind and solar as planet-saving technologies that must be adopted as quickly as possible to reduce carbon dioxide emissions and address global warming. While wind and solar can reduce some CO_2 emissions, their intermittency requires the use of coal or natural gas when the wind isn't blowing or the sun isn't shining, resulting in a situation where carbon dioxide will be emitted.

Carbon dioxide emissions are therefore a feature, not a bug, of wind and solar generation.

Minnesota is part of the Midcontinent Independent Systems Operator (MISO), an electricity network that orchestrates which power plants run, and when.[79] Figure 23 shows a real-time snapshot of electricity generation in MISO on January 30, 2019 at around 10 a.m., when a polar vortex caused the temperature in Minneapolis to plunge to -24° F.

During this time, coal, natural gas, nuclear, and wind provided 45 percent, 26 percent, 13 percent, and 4 percent of MISO's electricity generation, respectively.[80] It is worth noting wind power was utilizing just 24 percent of its installed capacity because of low wind speeds and the fact that wind turbines are routinely shut down at cold temperatures (-20° F) for safety reasons.[81]

Nuclear power can provide constant, reliable, carbon-dioxide-free electricity at all times of the day regardless of weather conditions. This is why areas of the world that consistently have the "greenest" electricity are areas where electricity is primarily generated by nuclear or hydroelectric energy.

Ontario, Canada routinely sources nearly all of its electricity from nuclear and hydroelectric power plants, which is why it has low CO_2 emissions around the clock, 365 days per year, even when the wind is not blowing (See Figure 24).[82]

If Minnesota lawmakers want to reduce CO_2 emissions around the clock, every day, they must legalize the construction of new nuclear power

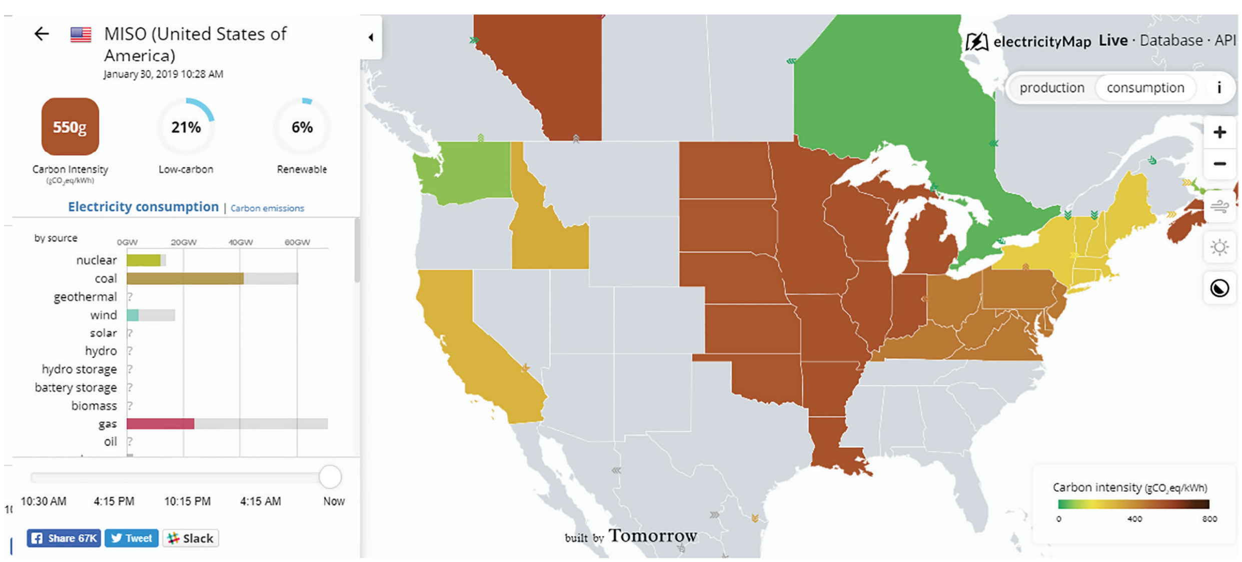


Figure 23. Despite heavy investments in wind turbines in MISO, coal accounted for 45 percent of power generation because of low wind speeds and the bitter cold, which forced some wind turbines to shut down for safety reasons.

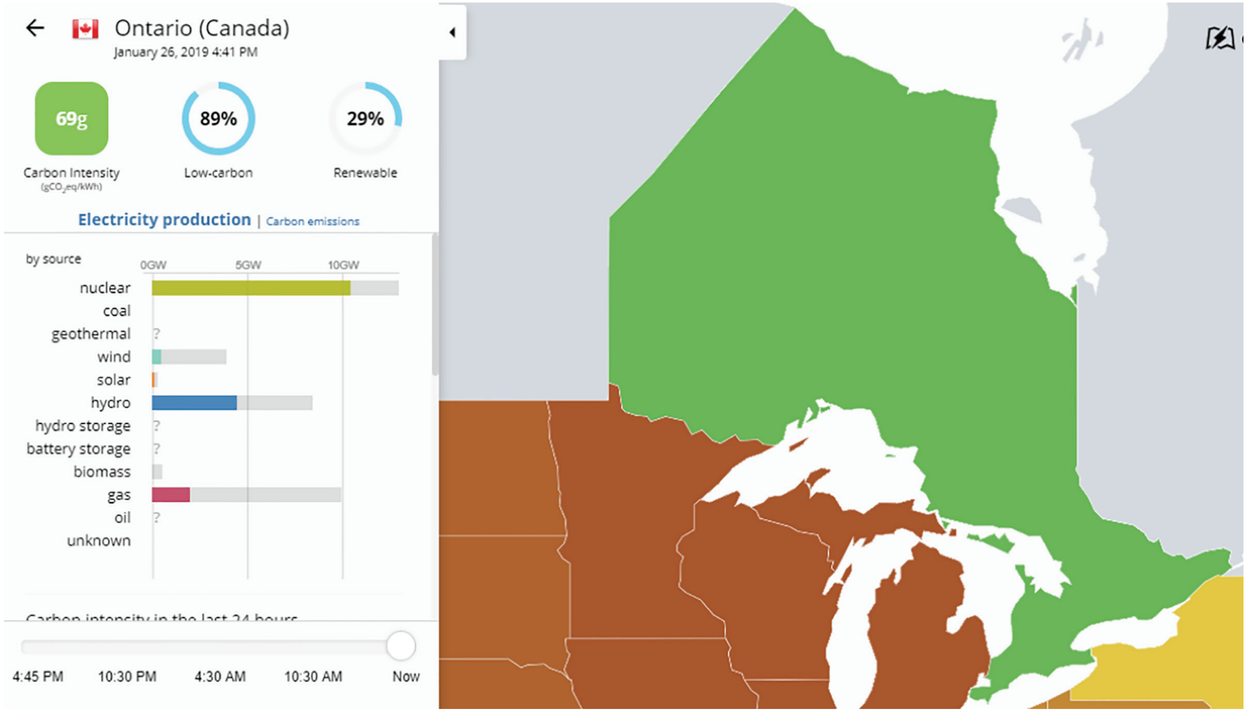


Figure 24. Carbon dioxide emissions are consistently low in Ontario because this Canadian province uses nuclear and hydroelectric power to generate the vast majority of its electricity. These sources are more effective at consistently producing carbon-dioxide-free electricity because their generation does not fluctuate based on the weather, as do wind and solar.

plants in Minnesota. A 50 percent renewable energy mandate would institutionalize carbon dioxide emissions for the foreseeable future by requiring coal or natural gas backup generation sources.

Would Reducing Minnesota's CO_2 Emissions Make a Difference in Global Temperatures?

If the key reason for reducing CO_2 emissions is to avert climate change, it makes sense to ask this question: Will reducing Minnesota's carbon dioxide emissions meaningfully affect global temperatures? The short answer is no.

Doubling Minnesota's renewable energy mandate would reduce CO_2 emissions from Minnesota's electric generating plants from 0.0283 gigatons (28.3 million metric tons) in 2017 to 0.0052 gigatons (5.2 million metric tons) in 2030. In 2018, global fossil-fuel-related CO_2 emissions reached 37.1 gigatons, meaning Minnesota's entire electric sector accounted for 0.00075 of global CO_2 emissions.[83] Doubling Minnesota's renewable energy mandate would bring our emissions down from 0.00075 to 0.00013 of global CO_2 emissions.

Because greenhouse gases mix evenly in the air, Minnesota would still incur 99.94 percent of the warming impact caused by rising greenhouse gas emissions from other states and countries. This is not to say we should throw our hands up and do nothing, but we must be realistic about the costs that will be borne by Minnesotans and the minute benefits they, or anyone else, would reap.

What impact will Minnesota's actions have on future temperatures? To understand how reducing Minnesota's 28.3 million metric tons of CO_2 emissions would impact global temperatures, it helps to examine the impact of the Clean Power Plan (CPP), widely considered to be the Obama administration's signature climate change initiative. Proponents claimed the CPP would have reduced annual CO_2 emissions nationally by 730 million metric tons by 2030.[84]

The Model for the Assessment of Greenhouse-Gas Induced Climate Change (MAGICC), the climate model used by the Environmental Protection Agency (EPA) during the Obama administration to estimate the CPP's effect on global temperatures, found the CPP would have reduced future warming by only 0.019° C by 2100, an amount too small to be accurately measured with even the most sophisticated scientific equipment.[85, 86]

The 23.3 million metric tons of CO_2 no longer emitted from power plants in Minnesota under the 50 percent REM and nuclear scenarios would be roughly 3.19 percent of the CO_2 reductions projected for the CPP. If CO_2 emissions from Minnesota power plants are reduced to 5 million metric tons per year, it would potentially avert 0.0006° C of warming by 2100, an amount far too small to be measured.

If asked if they would be willing to pay an additional $1,200 every single year for 31 years to avert 0.0006 of global CO_2 emissions and 0.0006° C of warming by 2100, most Minnesota families would likely prioritize that money for other expenditures.

If the purpose of enacting a 50 percent renewable energy mandate is to reduce carbon dioxide emissions in order to limit future global warming, then it will cost Minnesota families and businesses $80.2 billion through 2050 and only reduce global emissions by 0.0006 of the global total.

The Obama administration understood the Clean Power Plan would have a negligible impact on global temperatures, which is why Obama-era EPA administrator Gina McCarthy, at a hearing before the U.S. House Science Committee in July 2015, said the value of the Clean Power Plan was not to be measured by temperature reductions, but rather "measured in showing strong domestic action which can actually trigger global action to address what's a necessary action to protect [the planet]."[87]

If the primary aim of Minnesota's policymakers is to demonstrate leadership, lifting the state's ban on new nuclear power plants would be a powerful signal to the other 13 states that also have restrictions on the construction of new nuclear power plants—California, Connecticut, Hawaii, Illinois, Maine, Massachusetts, Montana, New Jersey, New York, Oregon, Rhode Island, Vermont, and West Virginia—not to mention developing countries that could utilize nuclear power to reduce CO_2 emissions immediately. If limiting carbon dioxide emissions is truly imperative, nuclear power must be on the table.[88]

Leadership means taking effective action to accomplish goals in the most efficient way possible, even if those actions are politically unpopular. Unnecessarily squandering tens of billions of dollars on less effective and more expensive solutions to perceived problems is not leadership.

What About Other Pollutants? NOx, SOx, Mercury, and Particulates?

Renewable energy advocates also claim that wind and solar will result in public health benefits by reducing pollutants—nitrous oxides, sulfur dioxide, mercury, lead, ozone, and fine particulates—that are emitted by coal or natural gas plants. Here too, the intermittent nature of wind and solar will likely result in greater emissions of these compounds relative to the Short-Term Nuclear scenario.

Additionally, it is important to note that data collected by the Minnesota Pollution Control Agency (MPCA) show Minnesota already meets the most-stringent air quality standards for these pollutants, and these standards are designed to protect the most vulnerable populations, such as children and the elderly (See Figure 25).

With the exception of ozone, all air pollutants have been below the most protective standard since 2003, years before wind and solar generated significant amounts of electricity in Minnesota.[89] Furthermore, emissions reductions in fine particulates, PM_{10}, nitrogen dioxide, and carbon monoxide reflect updated pollution regulations that allowed emissions to fall while Minnesota generated more than half of its electricity from coal-fired power plants.[90]

The MPCA data show Minnesota's air is already clean, and that pollution control equipment at coal-fired power plants can operate effectively, producing affordable and dependable electricity while maintaining a healthy environment. In fact, recent testimony by MPCA reveals fine particulates are down 20 percent since 2003, and efforts to reduce pollution from power plants and factories have been so successful that the chief contributor of fine particulates in Minnesota is residential wood burning.[91] Minnesota's eight air pollution alerts in 2018 were mostly due to smoke from wildfires and forest fires elsewhere, not coal-fired power plants.[92]

Section IV: Concluding Remarks

Minnesota lawmakers will be charged with making important decisions about the energy mix in our state moving forward, and they must carefully weigh the costs of each scenario against benefits reaped before deciding which energy mix will be the most fiscally and environmentally responsible for future generations.

A recent poll by the Associated Press and the University of Chicago asked how much respondents were willing to pay monthly to fight climate change. Fifty-seven percent of those surveyed said they would pay at least $1 per month, but only 23 percent said they would pay at least $40, and a mere 16 percent said they would pay more than $100 per month.[93]

If asked if they would be willing to pay an additional $1,200 every single year for 31 years to avert 0.0006 of global CO_2 emissions and 0.0006° C of warming by 2100, most Minnesota families would likely prioritize that money for other expenditures.

This reality will undoubtedly be mischaracterized or caricatured as an excuse to do nothing or even somehow as "un-Minnesotan," but this sobering truth should impress upon lawmakers the importance of using a rational cost-benefit analysis when making critical choices about Minnesota's energy future.[94]

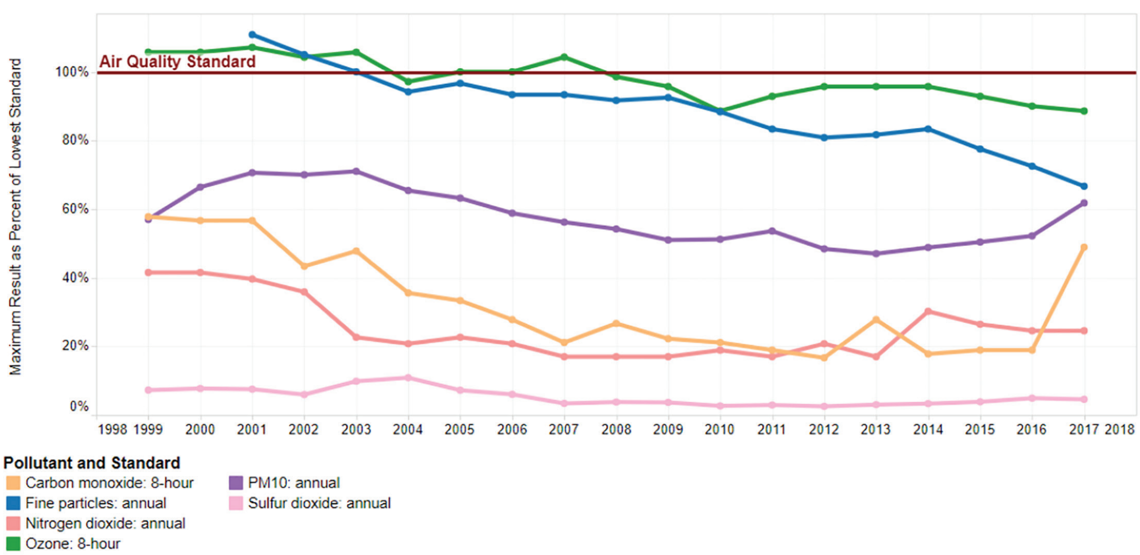


Figure 25. Air quality in Minnesota currently meets the most stringent standards for carbon monoxide, fine particulates, nitrogen dioxide, ozone, PM_{10}, and sulfur dioxide. Increases in carbon monoxide and PM_{10} annually from 2016 to 2017 reflect a reduction in the allowable limit of these substances, not an increase in their concentration.

Lawmakers seeking to enact a 50 percent renewable energy mandate must realize they are seeking to reduce emissions of CO_2 in the most expensive and least effective way possible. By keeping other options—such as nuclear power and large hydroelectric power—and technologies such as carbon capture and sequestration off the table, lawmakers seem to care more about making it appear as if Minnesota drives a Tesla, rather than seeking policies that would provide the best return on investment for all Minnesotans and the environment.

Appendix I: Calculating Generation Costs

This section explains much of the theory behind the cost of generating electricity in Minnesota. It explains how the costs of generating electricity were calculated in Section I, further elaborating on how a 50 percent renewable mandate would drive up the cost of electricity in Minnesota, why nuclear power plants could achieve the same reduction in carbon dioxide emissions for far less cost, and why existing coal-fired power plants would provide the most affordable electricity.

Levelized Cost of Energy

Generation costs reflect the cost of generating electricity from different types of power plants. These costs are often expressed as the Levelized Cost of Energy (LCOE), a figure that represents the per megawatt hour (MWh) cost of building and operating a generating plant over an assumed financial lifetime and the quantity of electricity generated by the plant (See Table 5).

Generation costs for existing energy sources were calculated based on data from the Federal Energy Regulatory Commission (FERC) Form 1 filings submitted by electric utilities in Minnesota. These data were used to construct LCOE estimates for existing power plants. (Please see Appendix II and Appendix X.)

Table 5 shows the unsubsidized LCOE of new and existing power plants at Minnesota-specific capacity factors and fuel prices, and using realistic payback periods. Table 5 also includes levelized transmission costs, levelized property tax costs, and levelized costs for utility profits.

These LCOEs were calculated using an LCOE calculator and cost assumptions from the U.S. Energy Information Administration (EIA). Assumptions for the Annual Energy Outlook for 2018 were used for capital costs, heat rates, variable operation costs, and fixed operation and maintenance costs. Fuel costs and capacity factors for wind and solar power plants in Minnesota were obtained from EIA data tables and used to tailor our findings for our state (See Figure 26).

Electricity customers do not pay for either renewables or natural gas, depending on which of these options is more affordable or more available at the time. They pay for both, at significant cost.

Capacity Factors

A capacity factor is the amount of electricity a power plant generated, expressed as a percentage, compared to what it could have produced if it were operating at 100 percent of its potential output.

For coal, natural gas, and nuclear power, humans control their capacity factors by deciding when and how much electricity they generate. The capacity factors for wind and solar are a function of fluctuating weather conditions.

Although the capacity factor for wind was 35.9 percent in 2017, this low capacity factor may be an artifact of older, less efficient wind turbines dragging down the fleet-wide average capacity factor. Therefore, we use a 44 percent capacity factor on new wind resources to account for technological improvements in more recent years, which we believe to be generous. Therefore, our cost calculations for unsubsidized new wind are likely conservative.

Levelized Cost of Energy				Levelized Additional Costs			
Source	Capacity Factors	Existing LCOE	New LCOE	Levelized Transmission	Levelized Property Tax	Levelized Utility Profit	Total LCOE
Coal	57%	$33.23	$33.23	NA	$0.19	$0.73	$34.15
	70%	$29.00	$29.00	NA	$0.16	$0.59	$29.75
Hydro	67%	$13.08	NA	NA	NA	NA	$13.08
Natural Gas (CT)	3%	$91.86	$407.11	NA*	$35.19	$131.97	$574.27
	4%	$72.21	$314.11	NA*	$26.39	$98.98	$439.48
	5%	$72.21	$258.12	NA*	$21.11	$79.18	$358.41
	6%	$67.05	$220.80	NA*	$17.60	$65.98	$304.38
	10%	$56.73	$146.07	NA*	$10.56	$39.59	$196.22
	15%	$51.56	$108.77	NA*	$7.04	$26.39	$142.20
Natural Gas (CC)	24%	$32.62	$62.30	NA*	$4.40	$16.50	$83.20
	28%	$31.28	$57.62	NA*	$3.52	$13.20	$74.34
	32%	$30.49	$52.50	NA*	$2.64	$9.90	$65.04
	36%	$30.12	$49.23	NA*	$2.11	$7.92	$59.26
	40%	$29.39	$46.61	NA*	$1.76	$6.60	$54.97
	70%	$27.51	$37.45	NA*	$1.51	$5.66	$44.62
Nuclear	85%	$42.82	$77.57	$0.08	$8.19	$30.69	$116.53
	91%	$41.70	$73.18	$0.07	$7.64	$28.67	$109.56
Utility Solar	18%	$60.91	$117.10	$13.05	$16.05	$60.20	$206.40
Community Solar	18%	$135.00	$135.00	NA	NA	NA	$135.00
Wind	35%	$55.17	$61.03	$9.57	$5.58	$20.93	$97.11
	44%	NA	$48.69	$7.61	$4.44	$16.65	$77.39

Table 5. Higher capacity factors result in lower LCOE values because the cost of generating electricity is spread over more units of electricity. Existing power plants produce electricity at lower costs because they have already paid down a portion of their "mortgages," which reduces the capital cost, and these plants are partially depreciated, reducing property taxes and utility profits (See Figure 6 and Figure 8).

**Utilizes existing transmission infrastructure.*

Useful Life of Generating Facilities

We use mortgage periods that reflect the actual useful lifetimes of the power plants. The National Renewable Energy Laboratory states wind turbines have a useful lifetime of only 20 years, while nuclear power plants are given an initial license of 40 years, with the ability to extend their licenses in 20-year increments. Xcel Energy currently has 25-year agreements with Community Solar installations. Therefore, our study uses 20-year mortgage periods for wind, 40 years for nuclear, 25 years for solar, and a 30-year mortgage period for natural gas plants.

This differs from EIA LCOE estimates which use a 30-year cost recovery period for all generation technologies, even though wind farms often need repowering after 20 years and coal and natural gas plants can easily run for 50 years with upgrades, and nuclear plants can be updated and retrofitted to run for 60 years and potentially longer.

Calculating the repayment period over 30 years does two things: It artificially reduces the cost of wind power by spreading its costs over 30 years, when 20 would be more appropriate, and it artificially inflates the cost of coal, natural gas, and nuclear by not calculating the cost over the entirety of their useful lifetimes.

We correct for these useful lifetimes to present the most realistic cost that will be borne by Minnesota families and businesses.

Why are These LCOEs Different than EIA and Lazard?

Some organizations cite LCOE estimates from EIA and Lazard's Levelized Cost of Energy Analysis to suggest that wind and solar are now more affordable than conventional sources of generation, such as coal, natural gas, and nuclear power. The differences between our LCOE estimates and those of Lazard and EIA are largely the product of assessing the mortgages over more appropriate timeframes and using Minnesota-specific capacity factors and fuel costs.

The Lazard study uses assumed capacity factors for

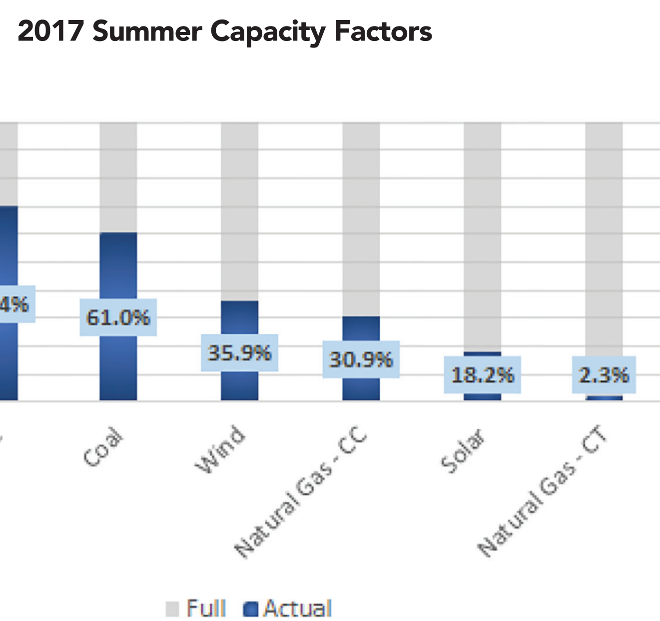


Figure 26. In Minnesota, the capacity factor for nuclear power plants was 95.8 percent, hydroelectric was 70.4 percent, coal was 61 percent, combined cycle natural gas was 30.9 percent, wind was 35.9 percent, solar was 18.2 percent, and combustion turbine natural gas was 2.3 percent.

wind ranging from 38 percent to 55 percent, and solar capacity factors are assumed to range from 21 percent to 32 percent. However, EIA data show wind and solar operations in Minnesota operate well under these capacity factors, with capacity factors at 35.9 percent and 18.2 percent, respectively, in 2017.

Interestingly, *no U.S. state* had an annualized solar capacity factor of 32 percent in 2017. Arizona and California had the highest solar capacity factors at 28.9 percent and 28.5 percent, respectively.

Utility profits would rise by $31.02 billion under the Renewable scenario, by far the most of any scenario.

Lastly, Lazard and EIA do not incorporate costs for generating backup electricity with natural gas or coal when the wind is not blowing or the sun is not shining, transmission costs, property taxes, or utility profits. Therefore, these cost estimates are not an estimate of the total cost of electricity that will be paid by consumers but rather a small piece of a much larger puzzle.

If the LCOE of Wind is Less than Nuclear, How Can the Nuclear Scenarios be Less Expensive?

Looking at Table 5, it is fair to wonder how the 50 percent renewable energy mandate under the Renewable scenario can cost nearly 40 percent more than the Short-Term Nuclear scenario, and more than 4.25 times more than the Long-Term Nuclear scenario, given that the LCOE of new wind power is less than that of new nuclear power.

The main reason the Renewable scenario is so expensive is because the grid must be overbuilt to ensure the reliability of an energy system dependent on intermittent wind and solar energy sources and overbuilt to reach renewable energy generation targets.

Overbuilding to Ensure Reliability

Enacting a 50 percent renewable energy mandate would not replace coal-fired power plants with wind and solar. It would replace coal-fired power plants with wind, solar, and natural gas—enough natural gas power plants to generate up to 100 percent of our electricity needs when wind and solar are generating zero electricity.

This is why Minnesota utilities plan to build 1.6 MW of wind, 0.62 MW of solar, *and* 1.1 MW of natural gas—for a total of 3.32 MW of generation capacity—for every 1 MW of coal-fired power they plan to retire (See Figure 27).

Overbuilding the grid with new wind and solar installations, along with adequate natural gas backup capacity, is incredibly expensive. Figure 28 shows the amount of installed capacity grows 24.2 percent from 18,396 MW in 2018 to more than 22,845.9 MW in 2030 to meet renewable energy targets and ensure reliable electricity when renewables are generating zero electricity. In essence, we will have built enough generation capacity to power 3.33 Minnesotas at today's electricity demand.

This growth in generation capacity does not reflect the 4,465.7 MW of coal that would be retired or the 2,100 MW of wind that would need to be repowered before 2030. Incorporating the coal closures and wind turbine rebuilds brings the total new capacity built between 2019 and 2030 to 11,015.6 MW, meaning 48 percent of the power plants on the grid would have been built in this 11-year timeframe.

Based on installed cost estimates from EIA, building and repowering these wind turbines, solar panels, and natural gas plants would cost $15.96 billion, not including costs for rising property taxes, transmission expenses, or utility profits.

It is crucially important for readers to understand that electricity customers do not pay for *either* renewables *or* natural gas, depending on which of these options is more affordable or more available at the time. They pay for both, at significant cost, even though many of these power plants will not

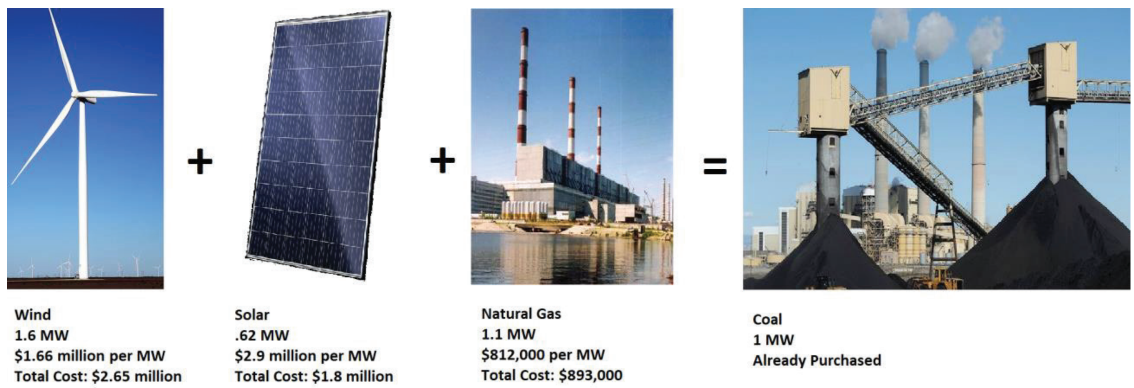


Figure 27. For every MW of coal that is retired, Minnesota utilities plan to build 3.32 MW of electricity generation—at a combined cost of $5 million per MW of coal replaced—simply to replace electricity generation capacity that we already have. These expenditures are the reason electricity prices in our state continue to climb.

be used much of the time. This is known as "idle capacity."

Idle Capacity

Many people do not realize that the grid is not a giant battery that stores electricity for later use. The amount of electricity generated by power plants must carefully match the demand for electricity at all times. Balancing the supply and demand—balancing the load, as it is described by utility companies—is like a teeter-totter that must always remain in equilibrium.

This means that if the wind is not blowing, natural gas plants must ramp up their production to meet demand, and if wind power is generating substantial quantities of energy, gas must dial back its

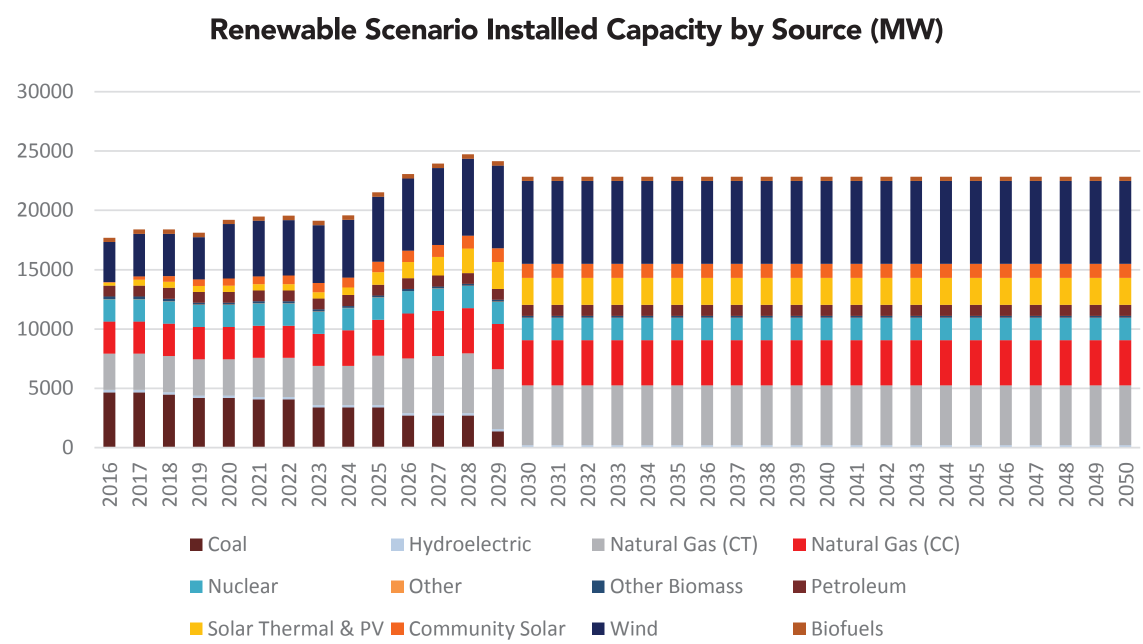


Figure 28. Wind comprises 6,972 MW of installed capacity, utility solar accounts for 2,268.6 MW, and community solar comprises 1,200 MW in 2030. Together, wind and solar account for 10,440 MW of capacity, whereas nuclear comprises 1,871 MW, CC gas 3,799.6 MW, and CT gas 5,044.8 MW.

production so as not to overload the grid.

Adding non-dispatchable sources of power like wind and solar necessarily results in a situation where a large portion of Minnesota's grid is sitting idle at any given time. This is demonstrated by the fact that the grid-wide capacity factor for the Renewable scenario is only 30 percent in 2050, compared to 56 percent in both nuclear scenarios and 55 percent in the ACE scenario.

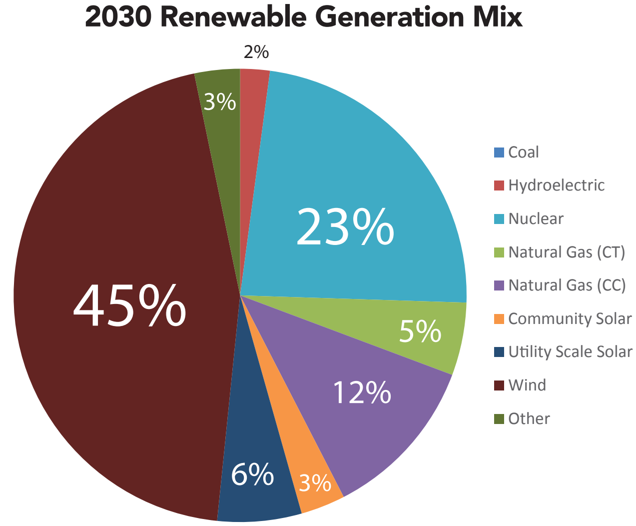
Even though 70 percent of the power plant generation capacity in the Renewable scenario would be idle at any given time, Minnesota families and businesses would still have to pay the costs associated with maintaining these power plants. That is why little-used plants make up a disproportionately large share of the cost of operating the grid (See Figure 29).

Fixed Costs for Power Plants

Every power plant has costs that are fixed, meaning they do not fluctuate based on how frequently the plant is used. Fixed costs include repaying capital costs (the "mortgage" on the plant), interest, insurance, salaries and wages, maintenance, and property taxes. Utility companies also make a guaranteed 7.5 percent profit on every single dollar they spend building new power plants, which is why they try to justify building as many as possible.

The only costs that need not be paid when facilities are idle are the costs of fuel and certain operation and maintenance costs. However, the savings from burning less fuel are often overstated. Claims that building renewables will make Minnesotans less vulnerable to spikes in the price of fossil fuels fail to consider that we will still burn natural gas when the wind is not blowing or the sun is not shining. Because the capacity factors of wind and solar in Minnesota are 35.9 percent and 18.2 percent, respectively, this means we will still burn large quantities of natural gas.

Furthermore, the delivered cost of natural gas in Minnesota is more expensive than burning coal, even after taking into consideration the fact that



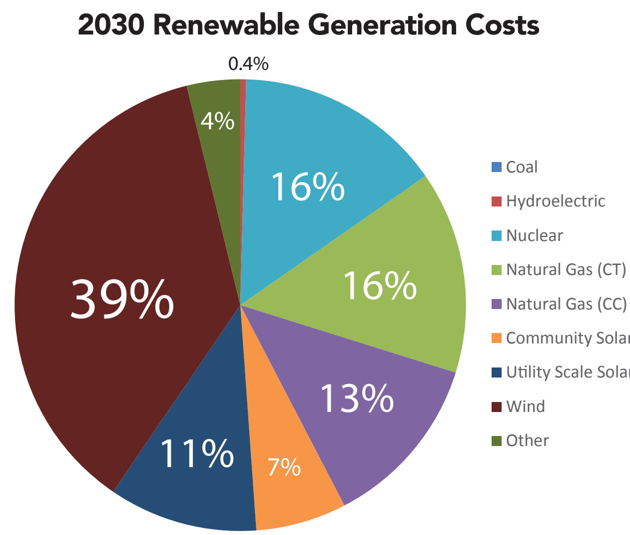


Figure 29. Low capacity factors result in large amounts of idle capacity on the grid. For example, Community Solar accounts for just 3 percent of generation (top pie), but 7 percent of generation costs (bottom pie). Likewise, Utility Scale Solar makes up 6 percent of generation but 11 percent of generation costs, and CT gas accounts for just 5 percent of generation but 16 percent of generation costs.

combined cycle natural gas plants are more efficient than coal-fired power plants.

This is why claims that Xcel Energy is "Swapping Steel for Fuel" are incorrect. Xcel Energy is swapping Steel and More-Expensive Fuel for Fuel, which is why the Renewable scenario is so much more expensive than either nuclear scenario or the ACE scenario.

Each nuclear scenario will save Minnesota at least

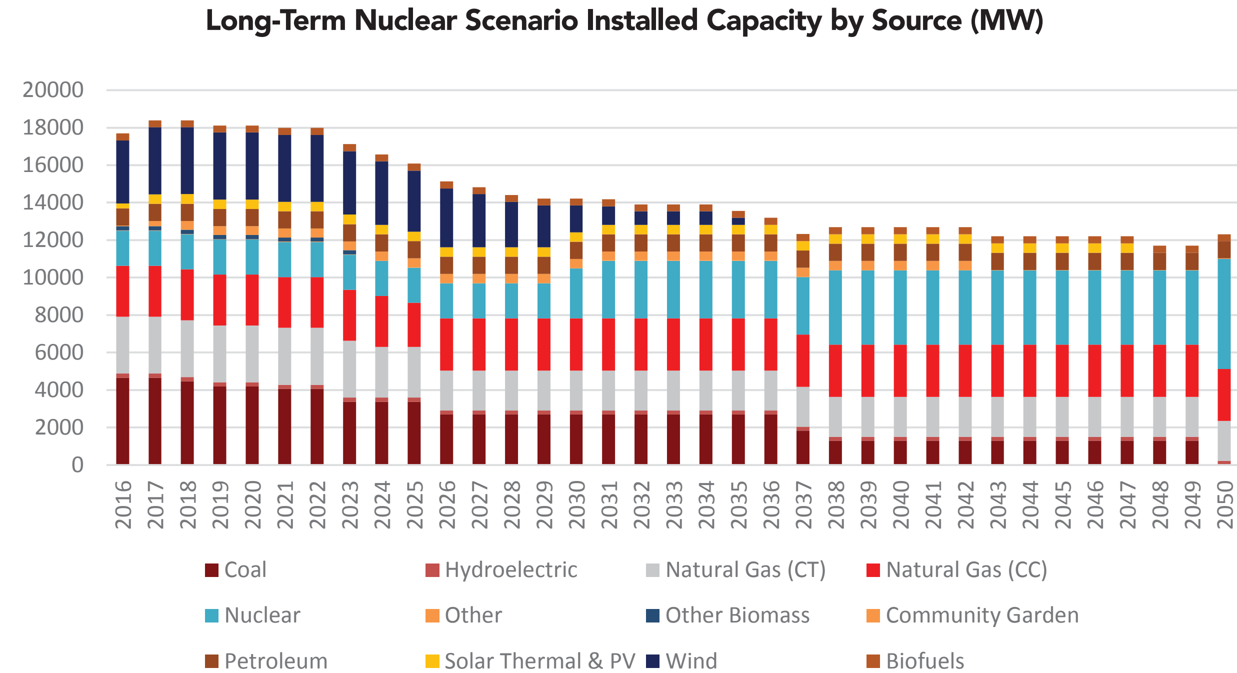


Figure 30. Electricity generating capacity falls from more than 18,000 MW of installed capacity in 2018 to 11,154.4 MW of installed capacity in 2050 as wind turbines gradually reach the end of their 20-year lifetimes and nuclear plants replace coal-fired power plants as they reach the end of their useful lifetimes.

$22.3 billion in part because the grid will not need to be overbuilt and because nuclear power plants can produce a steady, constant, and predictable flow of electricity and do not require backup power sources. Therefore, both nuclear scenarios would decrease the amount of installed capacity on the grid, representing a true "Steel for Fuel" scenario (See Figure 30).

Reducing the amount of capacity on the grid has the advantage of eliminating the fixed costs that are duplicated in the Renewable scenario. This means Minnesota will not be forced to pay twice for electricity it uses once. Reducing the amount of capacity on the grid has the added bonus of reducing transmission costs, property taxes, and utility profits.

Overbuilding to Meet Renewable Mandates

The other reason the grid must be overbuilt is to meet renewable energy mandates in the face of low capacity factors. To illustrate this point, imagine we wanted to generate 1 MW of power from wind on an annual basis. Because the capacity factor of wind in Minnesota was 35.9 percent in 2017, building 1 MW of wind capacity would result in only 0.359 megawatts of electrical output.

Figure 28 shows we would need to build 2.78 MW of wind capacity to achieve 1 MW of wind generation at Minnesota's 2017 capacity factor of 35.9 percent. Similarly, we would need to build 5.49 MW of solar capacity, at 2017 capacity factors, to generate 1 MW of power from solar. Nuclear, on the other hand, has a capacity factor of 91 percent in our study, and therefore we must build only 1.1 MW of nuclear capacity to generate 1 MW of power.

This overbuilding manifested itself in our study. Minnesota uses approximately 60 million megawatt hours of electricity every year, meaning we would need to get 30 million megawatt hours from renewable energy to satisfy the new mandate. Dividing 30 million by 8,760, the number of hours in a year, is 3,425. Thus, 3,425 MW of capacity would be needed to generate 30 million megawatt hours of electricity if the system were operating at a 100 percent capacity factor.

But wind and solar do not operate anywhere near 100 percent capacity factors, which is why Figure 28 on page 34 shows the installed capacity of wind is 6,972 MW, utility solar accounts for 2,268.6 MW, and community solar comprises 1,200 MW in 2030.

Furthermore, it is important to remember our study likely underestimated the amount of overbuilding that would need to occur, because we assume all newly built wind turbines will operate at a 44 percent capacity factor; therefore, requiring "only" 2.27 MW of wind to be built to achieve 1 MW of output.

The need to overbuild in this way significantly increases costs. For example, EIA's assumptions for its Annual Energy Outlook estimated the cost of wind to be $1.6 million per MW of installed capacity. However, this must be multiplied by 2.27 to get the actual amount that would need to be spent to generate 1 MW, resulting in a cost of $3.6 million per MW of power.

Likewise, the capital cost of solar ($2.105 million per MW) would need to be multiplied by 5.49, resulting in a cost of $11.55 million to generate 1 MW of electricity. The capital cost of nuclear ($5.946 million per MW) would need to be multiplied by 1.1, resulting in a cost of $6.5 million to generate 1 MW of electricity.

While these numbers do not influence the LCOE of specific generation sources, because the capacity factors of wind and solar are already taken into account, the need to overbuild adds considerable costs for transmission, property taxes, and utility profits.

Statement on Transparency

We strive to make *Doubling Down on Failure* the most transparent, straightforward, and realistic analysis of Minnesota's energy system. Therefore, all of the assumptions, charts, graphs, and data used to construct each scenario are available in Appendix II through Appendix XVI, online at AmericanExperiment.org. ■

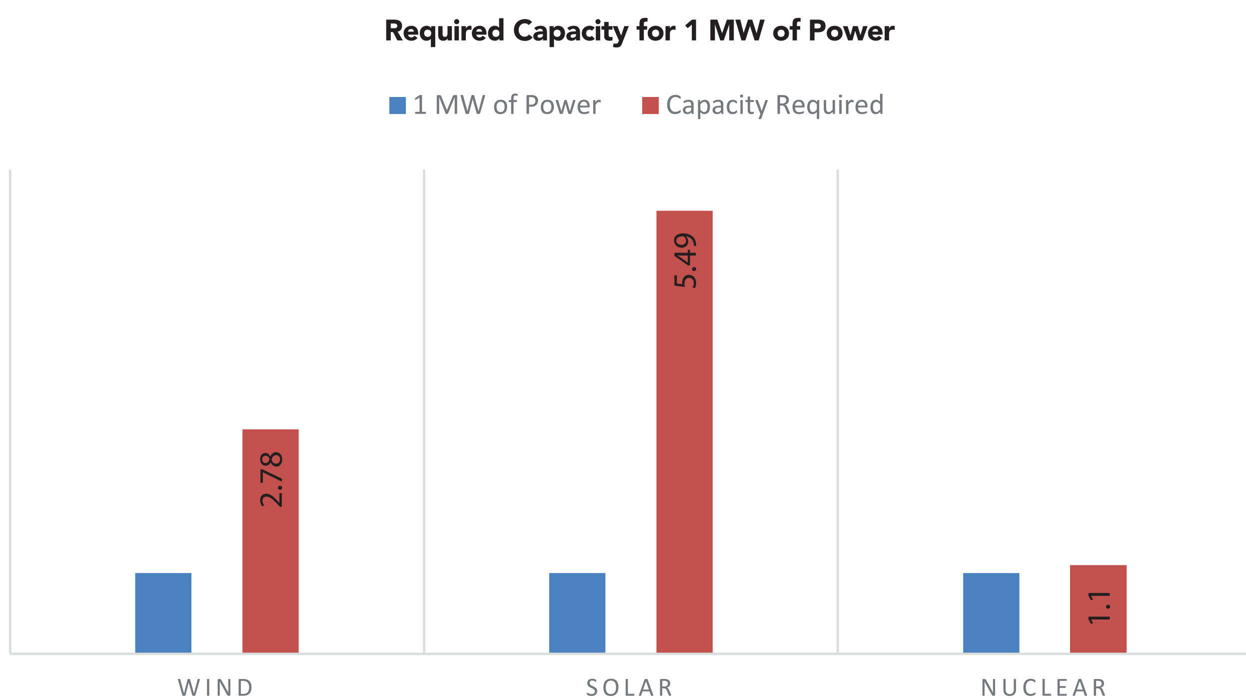


Figure 31. Using 2017 capacity factors for wind and solar, 2.78 MW of wind would need to be installed and 5.49 MW of solar would need to be installed to generate 1 MW of electricity.

Endnotes

1 Julia Pyper, "Xcel Energy Commits to 100% Carbon-Free Electricity by 2050," Greentech Media, December 4, 2018, https://bit.ly/2RaHtj5.

2 U.S. Environmental Protection Agency, "Regulatory Impact Analysis for the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program," Office of Air Quality Planning and Standards, August 2018, https://bit.ly/2BwEpLF.

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How a 50 Percent by 2030 Renewable Energy Standard Would Cost Minnesota $80.2 Billion

APPENDICES

ISAAC M. ORR, MITCH ROLLING, AND JOHN PHELAN

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APPENDICES

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1. Calculating Costs

Appendix II: Levelized Cost of Energy Calculations for Report

The Levelized Cost of Energy (LCOE) is often cited as a convenient summary measure of the overall cost competitiveness of different generating technologies. It represents the per megawatt hour (MWh) cost—in discounted real dollars—of building and operating a generating plant over an assumed financial life and duty cycle.[1] Key inputs for calculating LCOE values include capital costs, fuel costs, fixed and variable operational and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[2]

Federal LCOE values can be useful, but they are not reliable cost estimates for specific locations, like calculating the cost of generation in a specific state. As a result, we used an LCOE calculator to better account for the state-specific variables that affect the cost of electricity in Minnesota.[3]

LCOE values for new power plants were calculated using data values presented in the Assumptions to the Annual Energy Outlook 2018 published by the U.S. Energy Information Administration (EIA).[4] Capacity factors were then adjusted to reflect empirical data obtained by EIA for Minnesota.[5]

For existing sources, this report utilizes information obtained by Form 1 filings submitted by Minnesota utility companies to the Federal Energy Regulatory Commission (FERC). We compiled information dating back to 1994 to account for existing capital investment requirements still left to pay off, annual operational and maintenance costs, fuel costs, megawatt hours generated, and capacity factors for existing power plants.

FERC data was used to calculate the LCOE of existing resources on a dollars-per-megawatt-hour basis. The LCOE of existing sources for each technology was calculated using 2016 values by dividing the total cost to run each plant by the megawatt hour generation of each plant.

Future costs per MWh for existing resources were calculated by dividing the fixed costs detailed in FERC Form 1 data, in addition to future capital expenditures, by the estimated megawatt hour generation for each generation source based on annual capacity factors.

The equations for adjusting future LCOEs for existing generation sources are below.

Total Cost per MWh at 2016 Capacity Factors	-	Variable Cost per MWh	=	Fixed Cost per MWh at 2016 Capacity Factors		
Fixed Cost per MWh at 2016 Capacity Factors	*	2016 Capacity Factor	/	New Capacity Factor	=	New Cost per MWh

For example, the combined cycle natural gas facility Black Dog generated electricity at a cost of $29.20 per megawatt hour at a 40 percent capacity factor in 2016, of which included roughly $4.05 of fixed costs per MWh. To obtain a cost per MWh at a capacity factor of 30 percent, for instance, this report would multiply the fixed cost per MWh by the old capacity factor (40 percent) and divide by the new capacity factor (30 percent) to account for the decrease in generation that the facility's fixed costs are now being recovered by. Doing this, the new fixed cost becomes $5.40 and the new LCOE is $30.55.

This calculation is largely confirmed by looking at FERC Form 1 information. For Black Dog in 2015, the cost per MWh of electricity was $36.64 at a 31 percent capacity factor, about the same capacity factor as our calculation above. However, if we replace 2015 fuel costs of $3.66 per million British thermal units (MMBtu) with 2016 prices of $3.10 per MMBtu, the total cost of generation is closer to $31.40 per MWh. The rest of the difference in cost ($0.85) between our hypothetical calculation and the 2015 cost per MWh at 2016 gas prices is due to differing production expenses that occurred in 2015 and 2016. This study, however, holds production and fuel expenses constant throughout.

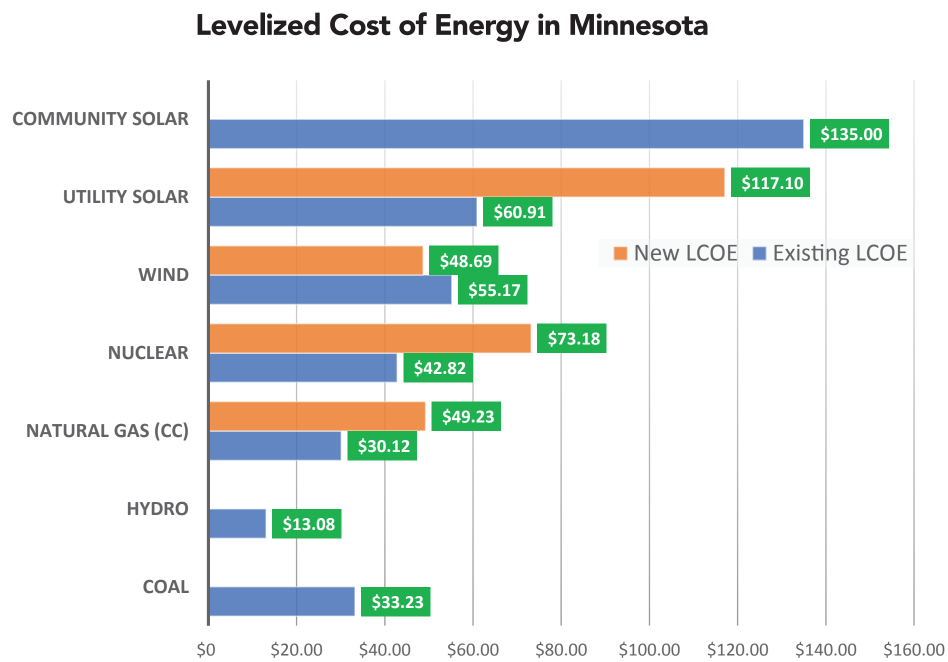

Figure 32. LCOE figures shown here are representative of the typical cost per MWh used in our report to calculate generation costs. As capacity factors change—particularly for natural gas and coal—these LCOE figures are changed to reflect the fluctuating capacity factors.

Due to lack of information on power purchase agreements (PPAs) and inconsistencies in FERC Form 1 data for wind farms in Minnesota, FERC Form 1 data was deemed insufficient on its own to determine a suitable LCOE for existing wind resources. Instead, this study utilizes research conducted by the Lawrence Berkeley National Laboratory, a subsidiary of the U.S. Department of Energy (DOE), which used data from FERC, U.S. Energy Information Administration (EIA), American Wind Energy Association (AWEA), and DOE's Lawrence Berkeley National Laboratory to determine an acceptable LCOE for existing wind turbines in different regions in the United States.[6]

Our report compiles the annual LCOE estimates for existing wind resources in the Interior region, of which Minnesota is a part, and weights the cost per megawatt hour per year with the capacity of wind installed in each year from 2008 to 2017. The average cost per megawatt hour, in 2007 dollars, was then used to approximate the cost per megawatt hour of existing wind facilities built during these years, which resulted in an LCOE for existing wind farms of approximately $55 per MWh.

Figure 32 shows the LCOE of new and existing generation resources in Minnesota. However, the figure is an "energy only" graph and does not include the costs of transmission, utility profits, property taxes, or load balancing.

Existing solar values are substantially lower due to the up-front, 30 percent Investment Tax Credit (ITC) granted to solar developers. This report did not adjust for the ITC for existing solar facilities, and as such, our assumptions for the real cost of existing solar generation are conservative. Community Solar prices are assumed to remain constant at $135 per megawatt hour.

Appendix III: Assumptions for Levelized Cost of Energy Calculations

Capital Cost Assumptions

Capital cost assumptions were derived from the Assumptions for the Annual Energy Outlook 2018,

Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2017 $/kW)	Project Contin-gency Factor[2]	Techno-logical Optimism Factor[3]	Total overnight cost[4,10] (2017 $/kW)	Variable O&M[5] (2017 $/MWh)	Fixed O&M (2017$/kW/yr)	Heat rate[6] (Btu/kWh)	nth-of-a-kind heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2021	650	4	4,641	1.07	1.03	5,089	7.17	70.70	9,750	9,221
Coal with 90% CCS	2021	650	4	5,132	1.07	1.03	5,628	9.70	82.10	11,650	9,257
Conv Gas/Oil Combined Cycle (CC)	2020	702	3	935	1.05	1.00	982	3.54	11.11	6,600	6,350
Adv Gas/Oil CC	2020	429	3	1,026	1.08	1.00	1,108	2.02	10.10	6,300	6,200
Adv CC with CCS	2020	340	3	1,936	1.08	1.04	2,175	7.20	33.75	7,525	7,493
Conv Combustion Turbine[7]	2019	100	2	1,054	1.05	1.00	1,107	3.54	17.67	9,880	9,600
Adv Combustion Turbine	2019	237	2	648	1.05	1.00	680	10.81	6.87	9,800	8,550
Fuel Cells	2020	10	3	6,192	1.05	1.10	7,132	45.64	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,148	1.10	1.05	5,946	2.32	101.28	10,460	10,460
Distributed Generation - Base	2020	2	3	1,479	1.05	1.00	1,553	8.23	18.52	8,969	8,900
Distributed Generation - Peak	2019	1	2	1,777	1.05	1.00	1,866	8.23	18.52	9,961	9,880
Battery Storage	2018	30	1	2,067	1.05	1.00	2,170	7.12	35.60	N/A	N/A
Biomass	2021	50	4	3,584	1.07	1.00	3,837	5.58	112.15	13,500	13,500
Geothermal[8,9]	2021	50	4	2,615	1.05	1.00	2,746	0.00	119.87	9,271	9,271
MSW - Landfill Gas	2020	50	3	8,170	1.07	1.00	8,742	9.29	417.02	18,000	18,000
Conventional Hydropower[8]	2021	500	4	2,634	1.10	1.00	2,898	1.33	40.05	9,271	9,271
Wind	2020	100	3	1,548	1.07	1.00	1,657	0.00	47.47	9,271	9,271
Wind Offshore[8]	2021	400	4	4,694	1.10	1.25	6,454	0.00	78.56	9,271	9,271
Solar Thermal[8]	2020	100	3	3,952	1.07	1.00	4,228	0.00	71.41	9,271	9,271
Solar PV - tracking[8,11]	2019	150	2	2,004	1.05	1.00	2,105	0.00	22.02	9,271	9,271
Solar PV - fixed tilt[8,11]	2019	150	2	1,763	1.05	1.00	1,851	0.00	22.02	9,271	9,271

1 - Represents the first year that a new unit could become operational.
2 - AACE International, the Association for the Advancement of Cost Engineering, has defined contingency as "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs."
3 - The technological optimism factor is applied to the first four units of a new, unproven design and reflects the demonstrated tendency to underestimate actual

Table 6. The table above provides cost-input assumptions for our LCOE analysis.

published by the Energy Information Administration. Our study used these assumptions for Total Overnight Capital costs, Variable O&M, Fixed O&M, and Heat rate as inputs into the LCOE calculator to derive the per megawatt hour cost of new generation assets in Minnesota.

Combined cycle (CC) natural gas inputs were taken from the "Conv Gas/Oil Combined Cycle CC," combustion turbine (CT) natural gas power plants used "Conv Combustion Turbine" values, new nuclear plants used "Adv Nuclear" values, wind used "Wind" values, and solar used "Solar PV- tracking" input values.

Different Technologies have Different Useful Lifespans

Wind Turbines Last 20 Years. Federal LCOE estimates seek to compare the cost of generating units over a 30-year time horizon. This is problematic for wind energy LCOE estimates because the National Renewable Energy Laboratory reports the useful life of a wind turbine is only 20 years before it must be repowered.[7] Our analysis corrects for this error by using a 20-year lifespan for wind projects before they are repowered and need additional financing.

Solar Panels Last 25 Years. According to the National Renewable Energy Laboratory, solar panels lose 1 percent of their generation capacity each year and last roughly 25 years.[8, 9] This degradation causes the cost per megawatt hour (MWh) of electricity to increase each year. Using this assumption, the price per MWh at Minnesota Power's Camp Ripley solar field would increase by nearly $20 by 2042. However, our study does not take solar panel degradation into account in our LCOE estimates, making our cost and generation estimates conservative.

New Nuclear Plants are Licensed for 40 Years. Capital costs for new nuclear plants were amortized over 40-year periods, rather than 30, because this is the amount of time nuclear plants are initially licensed for by the Nuclear Regulatory Commission. This corrects for EIA LCOE calculations that attribute 30-year lifespans for all energy technologies, which, in the case of nuclear power, artificially inflate the cost of electricity during the initial production years of the facility.

Natural Gas Plants are Amortized Over 30 Years. For the purpose of this study, we continue amortizing new natural gas facilities over 30-year periods.

Fuel Costs

Fuel costs used for LCOE calculations are derived from EIA data for delivered fuel costs to Minnesota power plants.[10] We hold these values constant throughout the entirety of the report.

Nuclear Fuel Costs. Nuclear fuel costs were assumed to be $0.81 per million British thermal units (MMBtu), which was the latest available price for Minnesota power plants provided by EIA.[11]

Natural Gas Fuel Costs. Natural gas prices were assumed to be $3.10 per MMBtu based on 2016 values. We held this fuel cost constant through 2050. As a result, our assumptions for natural gas prices will almost certainly be too low, and our estimates on the cost of natural gas generation are overly generous for natural gas plants.

Coal Fuel Costs. Coal cost assumptions of $2.06 per MMBtu were based on delivered fuel cost data reported by EIA for 2016, and these values were held constant through 2050.

Capacity Factors for New Generation Resources

Wind Capacity Factor. According to EIA data, the average annual capacity factor for wind generation in Minnesota is 35.9 percent.[12] These low capacity factors are likely a relic of old, less efficient wind turbines effectively bringing down the fleet-wide average.

For the purposes of this report, we assumed capacity factors for new wind farms in Minnesota will reach 44 percent. Improvements in capacity factors reflect better technology and the fact that numerous Minnesota-based companies are building wind farms in North Dakota to take advantage of better wind resources.[13]

Solar Capacity Factor. This study assumes a constant capacity factor of 18 percent for solar facilities, which reflects the most recent real-world capacity factor published by EIA.[14]

Nuclear Capacity Factor. This study uses a 91 percent capacity factor for LCOE estimates for new nuclear power plants.

Natural Gas Capacity Factor. For both combined cycle natural gas facilities and combustion turbine natural gas facilities, capacity factors fluctuate because natural gas is utilized to balance the electric grid, ensuring electricity supply matches demand. Natural gas is deployed in some years more than others to account for power plant closures and additions occurring in different years. These changes in utilization are accounted for in our study.

Appendix IV: Calculating Transmission Costs

Transmission costs were estimated separately for each scenario to account for the different transmission needs that each energy source requires.

Renewable energy sources—especially wind farms—require many miles of additional transmission lines in order to connect facilities, which are often in remote locations, to the people in need of electricity. Minnesota electricity providers are now building wind farms in neighboring states such as North Dakota and South Dakota to take advantage of more ideal wind conditions. Doing this will result in the need for hundreds of miles of transmission line additions to utilize the electricity coming from these distant wind facilities.

This contrasts with traditional sources of electricity, such as coal, natural gas, and nuclear power facilities, which can all be placed closer to heavily-populated areas and are able to take advantage of existing transmission infrastructure. As a result, the nuclear and ACE scenarios have dramatically lower additional transmission line expenses compared to the Renewable scenario.

For the Renewable scenario, this study doubles transmission expenses attributable to renewable energy sources based on Xcel's most recent rate impact report from the year 2020 onward.[15] These expenses were then doubled again to reflect the additional transmission costs other utilities in Minnesota (which provide one-half of the electricity generated in the state, with Xcel serving the other half) would incur as they achieve renewable integration levels above 40 percent of total generation.[16]

The Midcontinent Independent System Operator (MISO), Minnesota's electricity grid operator, explained the need for substantial transmission additions with rising levels of renewable generation after receiving an unprecedented number of generation installation requests in 2017 due to the transition to renewables.

"MISO's Generator Interconnection Queue has grown to more than 350 projects totaling 58 GW. This is an unprecedented amount of requested generation driven by phase-outs of wind production tax credits and investment tax credits for solar, expected coal retirements, and state renewable portfolio standards. MISO's West Region alone faces more than 22 GW of generation under study *and will require significant transmission to interconnect even a fraction of that level of new resources.*"[17] [Emphasis added]

MISO's West Region consists of Montana, North Dakota, South Dakota, Minnesota, and Iowa. The year 2020 was chosen because, from 2020 to 2029, over 9,000 megawatts of new wind, solar, and natural gas power capacity are scheduled for construction in Minnesota, based on resource plans filed by Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy.[18, 19, 20, 21]

This study does not account for additional transmission expenses resulting from new natural gas facilities. Therefore, our Renewable scenario, which adds more than 3,000 MWs of new natural gas capacity, represents a conservative estimate for transmission costs.

Both nuclear scenarios assume an additional investment of $25,102.88 per MW of nuclear capacity installed for transmission expenses based on cost information from a nuclear plant currently under construction in the United States, the Vogtle nuclear plant. In an August 31, 2018 filing to the Georgia Public Service Commission, Georgia Power stated the cost of interconnection and transmission for the 2,430 MW Vogtle nuclear plant would be $61 million, or $25,102.88 per MW installed.[22] This report then amortized these transmission investments over 30 years.

The ACE scenario assumes no substantial additional transmission costs because this scenario utilizes coal-fired power plants and transmission systems that already exist. The ability to use existing infrastructure such as transmission is an often-overlooked benefit of maintaining existing energy sources.

Appendix V: Calculating Utility Profits on New Power Plants and Transmission Lines

Investor-owned utilities (IOUs), such as Xcel Energy, Minnesota Power, and Otter Tail Power, are not truly private entities. They are government-sanctioned monopolies that have the exclusive right to sell electricity in their service territories. Due to this relationship with government oversight, utilities are guaranteed to make a profit.

However, in Minnesota, utilities are not allowed to make a profit on the electricity they sell. Instead, they are allowed to recover costs on, and profits from, investments on capital additions such as power plants, transmission lines, and even new corporate offices through electricity rates. For the purposes of our study, this profit was assumed to be a 7.5 percent return on undepreciated capital because this is the current rate of return for Xcel Energy and Otter Tail Power.[23, 24]

Energy Source	Capital Costs ($/MW)
Wind	$1,630,000
Solar	$2,434,000
Natural Gas	$895,000
Repowering Wind	$1,716,387
Nuclear	$5,946,000

Table 7. Values for wind, solar, and natural gas were obtained from construction cost data released by EIA in 2018. Nuclear costs were taken from the Assumptions of the Annual Energy Outlook published by EIA in 2018. Repowering wind costs were estimated by utilizing reports from the Lake Benton Wind Farm repowering cost.

Our capital cost assumptions utilize data from the Energy Information Administration (EIA).[25, 26, 27, 28] For repowering wind turbines, we utilized information from the Lake Benton repowering project.[29]

Many studies assume that the cost of wind energy will continue to decline. However, our study does not project further cost declines and holds these values constant throughout the report. We did this because in an earnings call to Xcel Energy Investors, Ben Fowke, Xcel Energy's chairman, president, and chief executive officer, suggested wind power would be prohibitively more expensive without the federal Production Tax Credit.

In the earnings call, Fowke said, "I think with wind, we're probably locking in with the 100 percent or in the case of Dakota Range, the 80 percent PTC wind prices that as those PTCs start to diminish and ultimately fall off, I think it'll take the technology a while to catch back up and—a decade."[30]

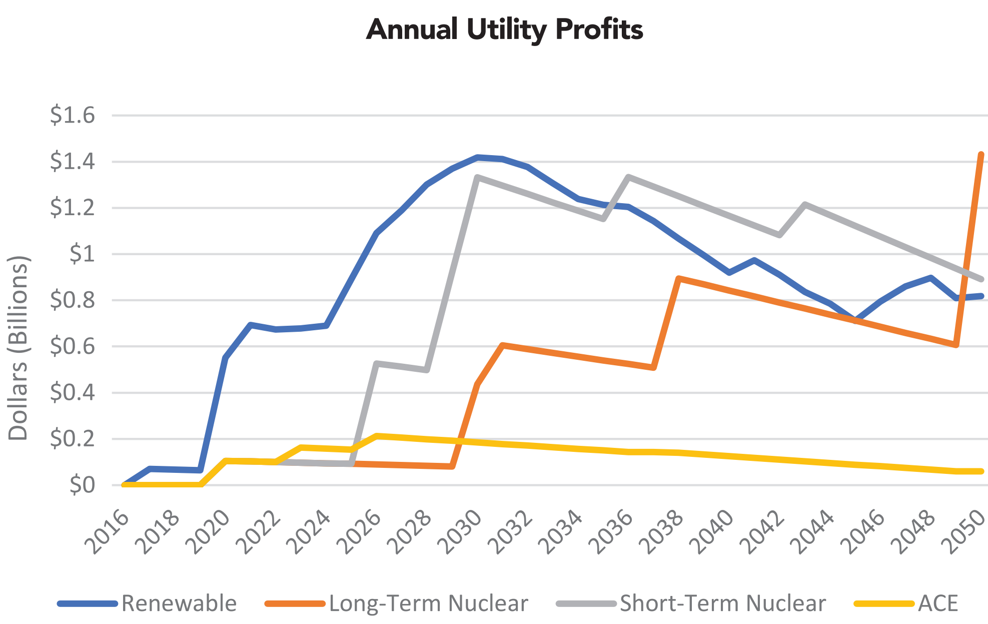

Figure 33. Utility profits are based on the depreciation schedules of each new generation source. Although both nuclear scenarios add the same amount of nuclear capacity, these facilities are added in different years according to our scenario requirements. The Long-Term Nuclear scenario, for example, spreads the cost of adding nuclear power plants over a longer period; thus, reducing the amount Minnesotans will be forced to pay through 2050 by utilizing existing generation sources.

The fact that utilities make a guaranteed profit on every dollar they spend on capital gives them a powerful incentive to build more generation resources. Based on our study, the Renewable scenario will not only guarantee utility companies the highest potential profits, it guarantees the continuation of these profits due to having to repower wind turbines every 20 years—which will require more capital investment and thus raise electricity prices even higher.

Appendix VI: Calculating Property Tax Payments from Utilities

Property taxes are paid on infrastructure such as power plants, transmission lines, distribution centers, and corporate buildings. Few, if any, studies examining the cost of transitioning to renewable energy sources consider this aspect in their cost calculations. This study is designed to correct for that omission.

Property tax expenses represent a substantial portion of utility expenses, and therefore represent a significant portion of the costs passed onto ratepayers. Furthermore, property tax expenses for utilities have increased dramatically as renewable energy sources have been added to Minnesota's electrical grid.

This is primarily due to two facts. One, wind and solar do not displace any existing capacity and, therefore, do not significantly reduce property tax payments paid on other power facilities. Two, property tax expenses rise significantly when utilities need to build hundreds of miles of new transmission lines to connect remote wind and solar energy facilities to the grid. This occurred after the CapX2020 transmission line initiative began in 2010, causing property tax expenses to increase for all utility companies that participated in it.[31]

For example, as Figure 34 shows, property tax expenses for Xcel Energy, Minnesota's largest electric utility, increased by nearly 132 percent after Minnesota began mandating renewable energy with the passage of the Next Generation Energy Act (NGEA) in 2007.[32] When the CapX2020 transmission initiative began in 2010, annual property tax expenses for Xcel rose by more than $25 million in the counties where these transmission lines were added, accounting for nearly 60 percent of Xcel's property tax increase from 2010 to 2014.[33]

Additional property tax payments were calculated to be 2 percent of the cost of undepreciated generation assets installed in each respective scenario, based on capital costs reported by EIA, and under the ACE scenario, capital costs associated with Selective Catalytic Reduction (SCR) and heat rate improvements required under ACE.[34, 35] Doing this allowed additional property tax expenses for each scenario to accurately track the capital spending for renewable energy assets, nuclear

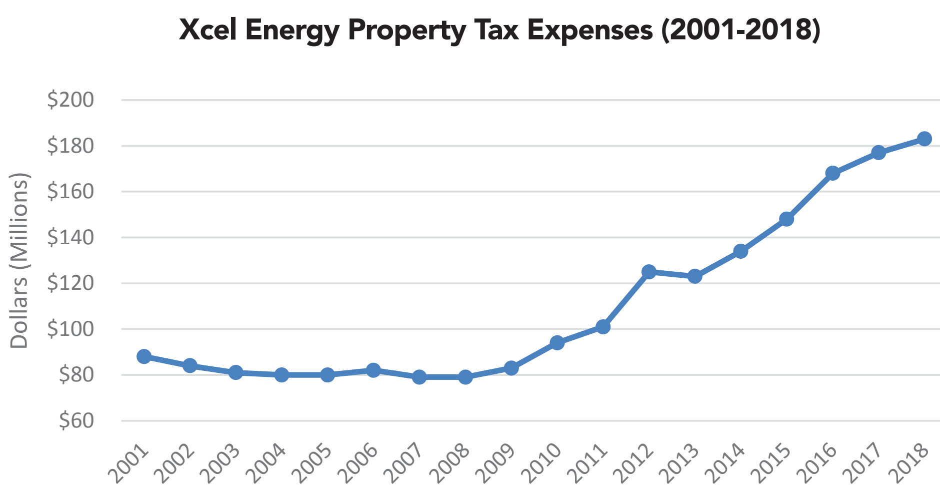

Figure 34. Property tax expenses have increased exponentially since 2007 when the Next Generation Energy Act was signed into law. This is largely due to additional property taxes assessed on wind turbines, solar panels, and transmission lines.

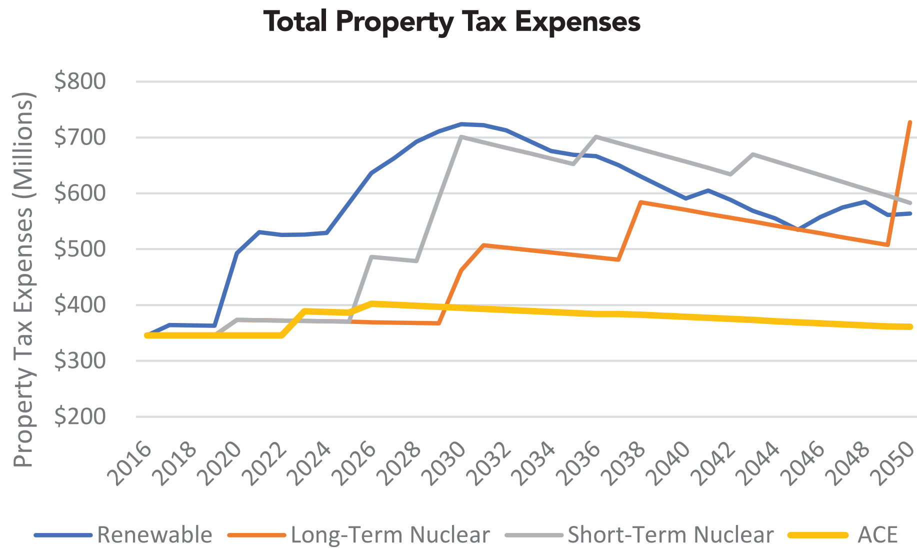

Figure 35. Although the property tax contributions of wind farms to local governments are smaller than those of other power plants due to special tax exemptions,[36] property taxes for the Renewable scenario are still the highest out of all scenarios. This is primarily caused by the capacity additions of dispatchable facilities providing backup for increased intermittent generation and the large amount of transmission lines needed to incorporate wind farms that are located in distant areas onto the electric grid. These property tax increases are significant, and because these payments are passed on to ratepayers, any report looking at the cost impacts of a transitioning energy grid should take property taxes into account.

plants, and coal plants. It also allowed for property tax payments to decrease—as they did for Xcel from 2001 to 2007 before the NGEA (shown in Figure 34)—in our scenarios as utilities utilize existing generation sources that have been depreciated, rather than building new power plants that Minnesota ratepayers don't need to meet electricity demand.

Appendix VII: Calculating the Average Cost per kWh for Each Scenario

For each scenario, we calculated the average additional cost per kWh of electricity over the course of our system's timeline. We did this by dividing the additional cost of each scenario by the total generation of each scenario through 2050.

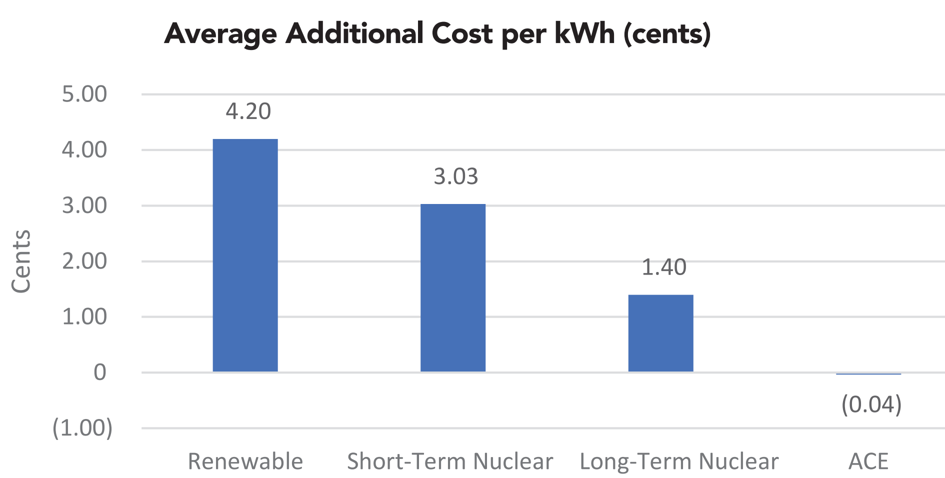

Figure 36. We calculated the average additional cost per kWh to address the impact of each scenario on Minnesota's industries and overall economy.

Our analysis did not address rate structures. Generation costs are derived from installation and operating costs and do not consider market payments and/or customer rate structures.

Appendix VIII: Calculating the True Cost of Wind and Solar Energy

After accounting for the actual lifespan of wind turbines (20 years) and solar panels (25 years), the true cost of electricity generated by wind and solar is $48.69 per MWh and $117.10 per MWh, respectively.[37, 38] These were estimated using a 44 percent capacity factor for wind and 18 percent for solar (See Table 8).

However, initial capital costs and O&M expenses are not the only costs associated with operating a power plant. The cost per megawatt hour increases further when accounting for the cost of transmission investment that will be needed to incorporate new wind and solar facilities in Minnesota, higher property taxes resulting from new transmission lines, wind farms and solar fields, and utility profits. Once these costs are incorporated, the LCOE for wind energy nears $80 per MWh and over $200 per MWh for solar.

Additionally, because wind and solar are intermittent energy sources, they require backup generation. This is an additional cost that intermittent sources of energy impose onto the grid and, therefore, it is more appropriate to attribute these costs to wind and solar in LCOE calculations. For simplicity, load balancing costs were calculated only for wind energy because the majority of load balancing generation capacity will be used to cover for when the wind stops blowing, although a small portion of this load balancing cost is attributable to solar energy, as well.

The methods used to calculate load balancing costs are described in more detail in Appendix IX.

Appendix IX: Levelized Cost of Transmission, Property Taxes, Utility Profits, and Load Balancing

This report calculated levelized transmission, property tax, and utility profit expenses resulting from each power source over the course of each facility's useful life and according to the additional capacity in MWs installed and generation in MWhs of that given source. Capacity installed is used to determine capital costs and additional expenses (transmission, property taxes, and utility profits) of each electricity source over the course of its useful lifespan. For example, a 200 MW combustion turbine natural gas facility would cost roughly $179 million based on our capital cost assumptions. This plant would also accumulate an expense of $208 million in utility profits and $55.5 million in property taxes over the course of the natural gas plant's 30-year lifespan, which are both paid for through electricity rates.

Energy Source	Capacity Factor	Levelized Cost		Levelized Trans		Levelized Property Tax		Levelized Utility Profit		**Total LCOE**
Wind	44%	$48.69	+	$7.61	+	$4.44	+	$16.65	=	**$77.39**
Energy Source	Capacity Factor	Levelized Cost		Levelized Trans		Levelized Property Tax		Levelized Utility Profit		**Total LCOE**
Solar	18%	$117.10	+	$13.05	+	$16.05	+	$60.20	=	**$206.40**

Table 8. The price per MWh of wind and solar energy nearly doubles for both electricity sources when factoring in the additional transmission, property tax, and utility profit expenses that result from these capacity installations.

Energy Source	Capacity Factor	Levelized Cost		Levelized Trans		Levelized Property Tax		Levelized Utility Profit		Load Balancing		**Total LCOE**
Wind	44%	$48.69	+	$7.61	+	$4.44	+	$16.65	+	$ 35.97	=	**$113.36**

Table 9. The load balancing cost of wind energy is almost as much as the generation LCOE of wind alone. This calculation was designed to show the true cost of wind energy in Minnesota and the real impact that intermittent resources impose onto the electricity grid.

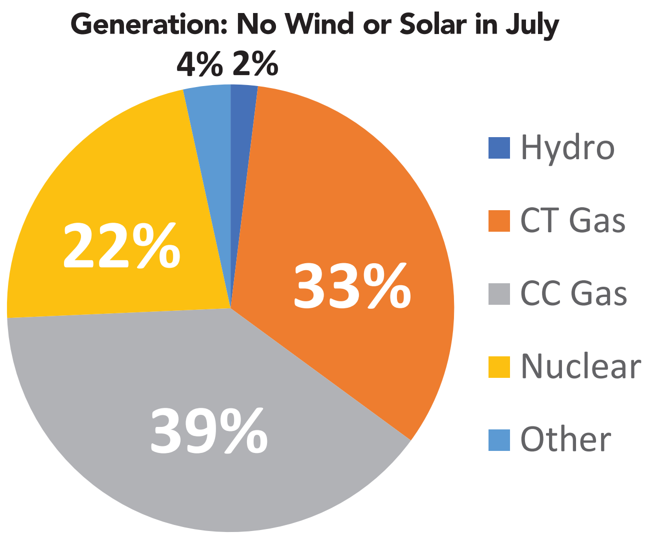

Figure 37. In a situation where wind and solar are producing zero electricity, natural gas is called in for backup. Combined cycle natural gas facilities would be required to run at an 85 percent capacity factor. Combustion turbine natural gas plants would reach a capacity factor of 54 percent, or higher, depending on electricity load. Having to maintain a natural gas fleet capable of meeting 100 percent of electricity demand, if needed, in addition to thousands of MWs of installed wind and solar capacity, is incredibly expensive.

We then calculated the levelized cost of these expenses over the number of MWhs that each technology would produce in this lifespan (according to the assumed capacity factors listed in Appendix III) by dividing the costs by the MWhs of electricity generated. For example, the same 200 MW combustion turbine natural gas facility would generate roughly 5.2 million megawatt hours of electricity if it ran at a constant 10 percent capacity factor over its 30-year lifespan. Therefore, the levelized cost of utility profit expenses over 30 years would be an extra $39.59 per MWh, and property taxes would be an extra $10.56 per MWh.

This report also calculated the levelized cost of load balancing for wind energy resulting from having to build backup generation to cover for windless days. Similar to levelized transmission, property tax, and utility profit expenses, this calculation was based on the capacity installations in the Renewable scenario, which are guided by resource plans filed by major utility companies in Minnesota, and attributed these costs to wind energy's LCOE.

We calculated the load balancing cost by determining how many MWs of combined cycle and combustion turbine natural gas capacity are being installed per 1 MW of wind installed (.3 MWs and .55 MWs, respectively) in order to calculate the capital cost associated with building load balancing generation sources. We then found the total cost of operating these resources based on their capacity factors of 24 percent and 5 percent, respectively, which are the rates these plants run during normal wind and solar conditions. Dividing the total cost of building and operating load balancing resources over the generation that 1 MW of wind power would produce at a 44 percent capacity factor then levelized these costs. We scaled these costs to account for the 3,605 MWs of wind that the Renewable scenario adds to the electricity grid. We attributed these costs to wind generation because the new installed capacity from natural gas is a result of increased wind generation on the grid, and as such, should be latched on to wind energy's total LCOE cost.[39]

To understand why load balancing is required in the Renewable scenario, Figure 37 shows the generation mix by source on a hypothetical July day when generation from wind and solar power is zero. We made sure there was enough adequate and reliable capacity on the grid to ensure that electricity demand is met for windless days and sunless nights. The cost to keep these plants online to cover for days like this is the load balancing cost.

Appendix X: Federal Energy Regulatory Commission Form 1 Data

We obtained the following information from Form 1 filings submitted by Xcel Energy, Otter Tail Power, and Minnesota Power to the Federal Energy Regulatory Commission (FERC). The tables show the year, plant name, total annual cost, total annual generation, the resulting cost per megawatt hour (MWh) of electricity, and annual capacity factors. Total cost estimates take into account existing capital obligations due to construction costs, any capital investments that have taken place since, operational and maintenance costs, and fuel costs. We then calculated the total cost per MWh for each power source according to each power plant's generation, cost, and capacity factor for the year 2016.

Coal

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Sherburne County	$ 312,498,765.00	10,002,378.06	$ 31.24	46%	2016	Boswell	$ 196,726,415.00	6,595,920.47	$ 29.83	78%
2015	Sherburne County	$ 352,597,873.00	10,219,972.81	$ 34.50	47%	2015	Boswell	$ 164,990,565.00	6,265,755.94	$ 26.33	74%
2014	Sherburne County	$ 378,090,743.00	11,200,690.71	$ 33.76	52%	2014	Boswell	$ 168,441,783.70	6,543,142.50	$ 25.74	78%
2013	Sherburne County	$ 358,286,736.00	8,547,413.82	$ 41.92	40%	2013	Boswell	$ 182,140,362.70	6,869,391.93	$ 26.51	82%
2012	Sherburne County	$ 289,798,317.00	8,257,298.42	$ 35.10	38%	2012	Boswell	$ 180,229,618.70	6,484,095.90	$ 27.80	77%
2011	Sherburne County	$ 356,006,849.00	11,209,754.34	$ 31.76	52%	2011	Boswell	$ 176,728,443.70	6,487,351.90	$ 27.24	77%
2010	Sherburne County	$ 315,665,320.00	11,235,537.55	$ 28.10	62%	2010	Boswell	$ 159,379,669.50	5,680,246.40	$ 28.06	67%
2009	Sherburne County	$ 321,715,056.00	12,928,818.49	$ 24.88	72%	2009	Boswell	$ 138,165,469.70	5,390,130.70	$ 25.63	64%
2008	Sherburne County	$ 301,566,362.00	12,144,241.00	$ 24.83	67%	2008	Boswell	$ 147,870,857.00	6,365,305.40	$ 23.23	76%
2007	Sherburne County	$ 281,049,718.00	13,042,301.00	$ 21.55	74%	2007	Boswell	$ 130,888,217.00	6,005,520.30	$ 21.79	71%
2006	Sherburne County	$ 218,897,507.00	12,872,777.00	$ 17.00	71%	2006	Boswell	$ 121,032,389.00	6,380,646.50	$ 18.97	76%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	0%	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Big Stone	$ 45,082,376.84	1,203,965.89	$ 37.44	62%	2016	Laskin				
2015	Big Stone	$ 38,523,023.84	836,480.58	$ 46.05	43%	2015	Laskin				
2014	Big Stone	$ 42,620,367.27	1,429,642.25	$ 29.81	73%	2014	Laskin	$ 15,708,227.90	347,844.30	$ 45.16	34%
2013	Big Stone	$ 40,079,359.27	1,513,249.91	$ 26.49	77%	2013	Laskin	$ 19,173,715.00	471,771.00	$ 40.64	46%
2012	Big Stone	$ 44,237,636.27	1,438,348.93	$ 30.76	74%	2012	Laskin	$ 18,213,508.90	368,364.40	$ 49.44	36%
2011	Big Stone	$ 40,549,530.27	1,337,249.06	$ 30.32	68%	2011	Laskin	$ 20,788,886.90	460,573.80	$ 45.14	45%
2010	Big Stone	$ 43,236,820.27	1,689,362.62	$ 25.59	86%	2010	Laskin	$ 21,083,399.90	516,368.60	$ 40.83	51%
2009	Big Stone	$ 40,663,447.27	1,587,452.88	$ 25.62	81%	2009	Laskin	$ 18,780,622.90	510,504.90	$ 36.79	50%
2008	Big Stone	$ 44,162,317.27	1,847,067.92	$ 23.91	94%	2008	Laskin	$ 18,904,718.90	659,438.80	$ 28.67	65%
2007	Big Stone	$ 30,263,235.27	1,318,470.54	$ 22.95	67%	2007	Laskin	$ 19,224,999.90	591,498.90	$ 32.50	58%
2006	Big Stone	$ 35,153,625.27	1,669,980.76	$ 21.05	85%	2006	Laskin	$ 16,820,898.90	623,975.50	$ 26.96	61%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	A S King	$ 117,987,794.47	2,715,572.90	$ 43.45	52%	2016	Taconite Harbor	$ -	-	$ -	0%
2015	A S King	$ 126,462,918.47	3,017,879.50	$ 41.90	58%	2015	Taconite Harbor	$ -	-	$ -	0%
2014	A S King	$ 139,422,304.47	2,992,942.00	$ 46.58	57%	2014	Taconite Harbor	$ 40,202,836.60	1,089,924.00	$ 36.89	55%
2013	A S King	$ 149,901,755.47	2,528,928.03	$ 59.27	48%	2013	Taconite Harbor	$ 46,406,548.60	1,064,434.00	$ 43.60	54%
2012	A S King	$ 128,694,226.47	3,364,278.91	$ 38.25	64%	2012	Taconite Harbor	$ 40,905,559.60	872,319.00	$ 46.89	44%
2011	A S King	$ 129,476,607.47	3,423,921.40	$ 37.82	65%	2011	Taconite Harbor	$ 40,704,463.60	1,116,764.00	$ 36.45	57%
2010	A S King	$ 123,567,238.47	3,490,060.50	$ 35.41	67%	2010	Taconite Harbor	$ 44,744,672.60	1,244,316.00	$ 35.96	63%
2009	A S King	$ 109,938,835.47	3,450,749.10	$ 31.86	66%	2009	Taconite Harbor	$ 34,366,232.60	1,058,263.00	$ 32.47	54%
2008	A S King	$ 102,373,875.47	3,173,853.00	$ 32.26	61%	2008	Taconite Harbor	$ 41,617,699.60	1,473,238.60	$ 28.25	75%
2007	A S King	$ 51,675,533.47	729,913.00	$ 70.80	0%	2007	Taconite Harbor	$ 39,470,585.60	1,491,457.30	$ 26.46	76%
2006	A S King	$ 45,248,200.00	1,665,905.00	$ 27.16	0%	2006	Taconite Harbor	$ 35,368,418.00	1,466,802.50	$ 24.11	74%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Coyote	$ 37,616,213.00	844,224.83	$ 44.56	67%	2016	Hoot Lake	$ -	215,935.02	$ -	0%
2015	Coyote	$ 21,250,333.00	662,451.13	$ 32.08	52%	2015	Hoot Lake	$ 18,630,515.00	295,853.60	$ 62.97	26%
2014	Coyote	$ 24,626,160.00	933,036.40	$ 26.39	74%	2014	Hoot Lake	$ 30,165,688.00	581,359.43	$ 51.89	52%
2013	Coyote	$ 23,954,401.00	881,972.84	$ 27.16	69%	2013	Hoot Lake	$ 27,824,613.00	809,359.30	$ 34.38	72%
2012	Coyote	$ 24,979,766.00	782,358.15	$ 31.93	62%	2012	Hoot Lake	$ 26,303,593.00	655,939.40	$ 40.10	58%
2011	Coyote	$ 23,526,953.00	1,062,153.41	$ 22.15	84%	2011	Hoot Lake	$ 29,090,576.00	787,922.19	$ 36.92	70%
2010	Coyote	$ 22,098,902.00	1,060,954.07	$ 20.83	84%	2010	Hoot Lake	$ 29,011,775.00	809,772.40	$ 35.83	72%
2009	Coyote	$ 26,665,053.00	856,358.75	$ 31.14	67%	2009	Hoot Lake	$ 25,642,828.00	598,691.60	$ 42.83	53%
2008	Coyote	$ 21,556,177.00	1,016,828.47	$ 21.20	80%	2008	Hoot Lake	$ 29,664,449.00	765,991.80	$ 38.73	68%
2007	Coyote	$ 19,386,166.00	1,032,449.24	$ 18.78	81%	2007	Hoot Lake	$ 28,225,926.00	955,328.40	$ 29.55	85%
2006	Coyote	$ 18,847,161.00	981,477.89	$ 19.20	77%	2006	Hoot Lake	$ 25,310,469.00	869,741.60	$ 29.10	77%

	2016
Total Cost:	$ 709,911,564.31
Total Generation	21,362,062.14
Avg. Cost per MWh	$ 33.23

**Per megawatt hour costs have an inverse relationship with capacity factors. Therefore, as capacity factors decrease, costs per megawatt hour increase. This is why Clay Boswell Units 3 and 4 had the lowest cost per megawatt hour while operating at a 78 percent capacity factor in 2016.*

Natural Gas (CC)

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Black Dog Unit 5	$ 33,425,368.70	1,144,543.0	$ 29.20	40.23%
2015	Black Dog Unit 2 & 5	$ 32,224,152.70	879,478.0	$ 36.64	30.91%
2014	Black Dog Unit 2 & 5	$ 28,185,891.70	431,068.1	$ 65.39	15.15%
2013	Black Dog Unit 5	$ 26,014,582.70	433,752.2	$ 59.98	15.25%
2012	Black Dog 2 & 5	$ 13,449,744.70	161,427.8	$ 83.32	5.67%
2011	Black Dog 2 & 5	$ 22,835,966.70	313,083.0	$ 72.94	11.00%
2010	Black Dog 2&5	$ 26,835,514.70	384,469.1	$ 69.80	13.51%
2009	Black Dog 2&5	$ 29,316,713.70	453,709.9	$ 64.62	15.95%
2008	Black Dog 2&5	$ 33,305,609.70	325,894.0	$ 102.20	11.69%
2007	Black Dog Unit 5	$ 46,667,091.70	668,231.0	$ 69.84	23.98%
2006	Black Dog Unit 5	$ 24,442,435.70	487,298.0	$ 50.16	17.48%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	High Bridge 7, 8, 9	$ 63,047,512.90	2,125,527.0	$ 29.66	37.68%
2015	High Bridge 7, 8, 9	$ 67,536,572.90	1,938,831.0	$ 34.83	34.37%
2014	High Bridge 7, 8, 9	$ 62,217,198.90	1,016,760.0	$ 61.19	18.02%
2013	High Bridge 7, 8, 9	$ 73,312,542.00	1,884,826.0	$ 38.90	33.41%
2012	High Bridge 7, 8, 9	$ 72,916,980.90	1,853,376.0	$ 39.34	32.85%
2011	High Bridge 7,8 & 9	$ 56,047,299.90	796,128.0	$ 70.40	14.11%
2010	High Bridge 7,8 & 9	$ 60,055,086.90	885,252.0	$ 67.84	15.69%
2009	High Bridge 7,8 & 9	$ 60,704,461.90	708,126.0	$ 85.73	12.55%
2008	High Bridge 7,8 & 9	$ 68,035,728.90	582,928.0	$ 116.71	10.33%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Riverside	$ 75,294,296.50	2432580.177	$ 30.95	47%
2015	Riverside	$ 90,083,656.50	2642154.031	$ 34.09	51%
2014	Riverside	$ 64,794,599.50	1007622.799	$ 64.30	20%
2013	Riverside	$ 71,409,562.50	1411382.816	$ 50.60	28%
2012	Riverside	$ 78,526,577.50	1953054.672	$ 40.21	38%
2011	Riverside 9 & 10	$ 50,326,485.50	597606.872	$ 84.21	12%
2010	Riverside 9 & 10	$ 61,672,357.00	980040.53	$ 62.93	19%
2009	Riverside 7, 9 & 10	$ 41,571,053.50	470372.078	$ 88.38	9%
2008	Riverside				

Total Cost	$ 171,767,178.10
Total Generation	5,702,650.17
Avg. Cost per MWh	$ 30.12

Natural Gas (CT)

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Blue Lake	$ 11,635,719.50	197,208.0	$ 59.00	4.02%
2015	Blue Lake	$ 10,492,717.50	69,277.0	$ 151.46	1.41%
2014	Blue Lake	$ 8,622,642.50	36,448.0	$ 236.57	0.74%
2013	Blue Lake	$ 10,797,810.50	109,089.0	$ 98.98	2.23%
2012	Blue Lake	$ 15,389,088.50	246,474.0	$ 62.44	5.03%
2011	Blue Lake	$ 10,914,695.50	95,014.0	$ 114.87	1.94%
2010	Blue Lake	$ 10,155,609.00	117,402.0	$ 86.50	2.40%
2009	Blue Lake	$ 5,907,884.50	13,408.0	$ 440.62	0.27%
2008	Blue Lake	$ 7,667,243.50	14,981.0	$ 511.80	0.31%
2007	Blue Lake	$ 21,471,499.50	139,399.0	$ 154.03	2.85%
2006	Blue Lake	$ 15,891,862.50	146,148.0	$ 108.74	2.98%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Solway	$ 2,754,715.87	39,508.5	$ 69.72	10.13%
2015	Solway	$ 2,609,233.87	17,660.3	$ 147.75	4.53%
2014	Solway	$ 4,741,940.87	42,384.6	$ 111.88	10.87%
2013	Solway	$ 3,276,112.87	42,778.2	$ 76.58	10.97%
2012	Solway	$ 3,815,956.87	53,965.4	$ 70.71	13.84%
2011	Solway	$ 3,272,978.87	31,623.9	$ 103.50	8.11%
2010	Solway	$ 3,909,206.00	43,818.5	$ 89.21	11.24%
2009	Solway	$ 3,389,468.87	26,361.4	$ 128.58	6.76%
2008	Solway	$ 5,937,704.00	47,234.2	$ 125.71	12.12%
2007	Solway	$ 5,872,460.00	53,833.7	$ 109.09	13.81%
2006	Solway	$ 3,739,132.00	28,098.7	$ 133.07	7.21%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Angus Anson	$ 6,848,692.00	65,635.5	$ 104.34	1.85%
2015	Angus Anson	$ 10,585,801.00	103,037.5	$ 102.74	2.90%
2014	Angus Anson	$ 6,659,010.00	25,796.0	$ 258.14	0.73%
2013	Angus Anson	$ 7,086,026.00	40,067.7	$ 176.85	1.12%
2012	Angus Anson	$ 9,649,705.00	112,729.3	$ 85.60	3.17%
2011	Angus Anson	$ 7,311,788.00	53,838.3	$ 135.81	1.52%
2010	Angus Anson	$ 10,517,667.00	84,888.4	$ 123.90	2.34%
2009	Angus Anson	$ 6,558,393.00	15,073.9	$ 435.08	0.42%
2008	Angus Anson	$ 20,754,620.00	120,595.0	$ 172.10	3.50%
2007	Angus Anson	$ 32,056,030.00	278,165.0	$ 115.24	8.13%
2006	Angus Anson	$ 21,205,199.00	208,101.0	$ 101.90	6.08%
2005	Angus Anson	$ 32,177,005.00	243,960.0	$ 131.89	7.13%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Jamestown	$ 804,598.00	317.5	$ 2,534.53	0.08%
2015	Jamestown	$ 291,045.00	79.8	$ 3,649.15	0.02%
2014	Jamestown	$ 722,268.00	1,073.0	$ 673.10	2.55%
2013	Jamestown	$ 309,054.00	273.8	$ 1,128.89	0.07%
2012	Jamestown	$ 1,250,673.00	1,369.4	$ 913.32	0.32%
2011	Jamestown	$ 822,867.00	1,373.0	$ 599.34	0.33%
2010	Jamestown	$ 274,483.00	292.4	$ 938.85	0.07%
2009	Jamestown	$ 444,949.00	754.6	$ 589.66	0.18%
2008	Jamestown	$ 1,072,667.00	1,286.2	$ 833.96	0.30%
2007	Jamestown	$ 1,824,251.00	4,268.0	$ 427.42	1.01%
2006	Jamestown	$ 2,003,653.00	3,128.7	$ 640.40	0.74%
2005	Jamestown	$ 4,539,228.00	5,998.9	$ 756.68	1.42%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Inver Hills	$ 2,438,349.00	17,436.0	$ 139.85	0.72%
2015	Inver Hills	$ 2,061,570.00	5,716.2	$ 360.65	0.23%
2014	Inver Hills	$ 4,092,998.00	2,760.6	$ 1,482.63	0.11%
2013	Inver Hills	$ 3,100,962.00	19,759.5	$ 156.93	0.80%
2012	Inver Hills	$ 5,488,915.00	40,504.1	$ 135.52	1.65%
2011	Inver Hills	$ 6,216,674.00	26,448.7	$ 235.05	1.08%
2010	Inver Hills	$ 5,650,016.00	46,836.8	$ 120.63	1.91%
2009	Inver Hills	$ 4,467,362.00	11,759.1	$ 379.91	0.48%
2008	Inver Hills	$ 7,747,368.00	22,966.0	$ 337.34	0.80%
2007	Inver Hills	$ 21,483,670.00	131,204.0	$ 163.74	4.59%
2006	Inver Hills	$ 9,492,347.00	61,138.0	$ 155.26	2.14%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Laskin	$ 6,747,467.00	11,433.2	$ 590.17	1.19%
2015	Laskin	$ 15,797,503.00	89,327.9	$ 176.85	9.27%

Total Cost	$ 30,424,943.37
Total Generation	331,221.17
Avg. Cost per MWh	$ 91.86

Nuclear

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Prairie Island	$ 347,245,095.90	8,263,058.00	$ 42.02	79.52%	2016	Monticello	$ 236,569,365.00	5,597,758.00	$ 42.26	93.29%
2015	Prairie Island	$ 338,144,426.90	7,374,711.00	$ 45.85	70.97%	2015	Monticello	$ 243,880,461.00	4,663,895.00	$ 52.29	77.73%
2014	Prairie Island	$ 361,591,864.90	8,383,200.00	$ 43.13	80.68%	2014	Monticello	$ 255,502,598.00	4,263,180.00	$ 59.93	71.05%
2013	Prairie Island	$ 340,707,820.90	7,714,143.00	$ 44.17	74.34%	2013	Monticello	$ 225,912,509.00	2,993,574.00	$ 75.47	49.89%
2012	Prairie Island	$ 278,674,252.97	7,061,651.00	$ 39.46	67.96%	2012	Monticello	$ 211,520,722.00	4,890,374.00	$ 43.25	81.50%
2011	Prairie Island	$ 290,387,791.97	8,602,247.00	$ 33.76	82.78%	2011	Monticello	$ 195,509,305.00	3,356,278.00	$ 58.25	55.93%
2010	Prairie Island	$ 291,744,142.97	8,782,935.00	$ 33.22	84.52%	2010	Monticello	$ 163,174,186.00	4,695,113.00	$ 34.75	84.91%
2009	Prairie Island	$ 255,954,845.97	8,250,961.00	$ 31.02	79.40%	2009	Monticello	$ 144,190,910.00	4,142,464.00	$ 34.81	74.92%
2008	Prairie Island	$ 192,206,306.97	8,115,144.00	$ 23.68	78.10%	2008	Monticello	$ 124,058,530.00	4,878,016.00	$ 25.43	88.22%
2007	Prairie Island	$ 194,498,202.97	8,889,286.00	$ 21.88	85.54%	2007	Monticello	$ 148,141,355.00	4,192,269.00	$ 35.34	75.82%
2006	Prairie Island	$ 214,982,208.97	8,110,867.00	$ 26.51	78.06%	2006	Monticello	$ 112,519,919.00	5,072,551.00	$ 22.18	91.74%
2005	Prairie Island	$ 181,181,380.97	8,363,301.00	$ 21.66	80.49%	2005	Monticello	$ 127,392,284.00	4,474,918.00	$ 28.47	80.93%
2004	Prairie Island	$ 174,816,727.97	8,260,260.00	$ 21.16	79.49%	2004	Monticello	$ 104,168,120.00	5,034,871.00	$ 20.69	91.06%
2003	Prairie Island	$ 178,732,488.97	8,837,318.00	$ 20.22	85.05%	2003	Monticello	$ 112,910,245.00	4,576,510.00	$ 24.67	82.77%
2002	Prairie Island	$ 192,907,822.00	8,669,267.00	$ 22.25	83.43%	2002	Monticello	$ 97,127,170.00	5,015,557.00	$ 19.37	90.71%

Total Cost	$ 583,814,460.90
Total Generation	13,860,816.00
Cost per MWh	42.1197757

Hydro

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Thomson	$ 6,169,191.00	417,419.18	$ 14.78	65.63%	2016	Fond Du Lac	$ 946,815.00	69,190.23	$ 13.68	71.80%
2015	Thomson	$ 5,573,823.00	199,037.36	$ 28.00	31.30%	2015	Fond Du Lac	$ 967,098.00	44,863.00	$ 21.56	46.56%
2014	Thomson	$ 4,191,970.00	11,923.20	$ 351.58	1.87%	2014	Fond Du Lac	$ 2,356,907.00	34,340.22	$ 68.63	32.67%
2013	Thomson	$ 2,808,712.00	-			2013	Fond du Lac	$ 901,157.00	14,312.15	$ 62.96	13.62%
2012	Thomson	$ 5,142,864.00	136,467.60	$ 37.69	21.46%	2012	Fond du Lac	$ 910,074.00	-		
2011	Thomson	$ 4,578,884.00	212,585.60	$ 21.54	33.43%	2011	Fond du Lac	$ 1,115,584.00	26,540.80	$ 42.03	25.25%
2010	Thomson	$ 3,548,486.00	197,934.00	$ 17.93	31.12%	2010	Fond du Lac	$ 1,122,141.00	39,477.40	$ 28.42	37.55%
2009	Thomson	$ 4,081,043.00	223,602.20	$ 18.25	35.16%	2009	Fond du Lac	$ 840,301.00	39,695.50	$ 21.17	37.76%
2008	Thomson	$ 3,783,423.00	270,412.70	$ 13.99	42.52%	2008	Fond du Lac	$ 1,176,007.00	50,269.70	$ 23.39	47.82%
2007	Thomson	$ 2,581,535.00	236,646.40	$ 10.91	37.21%	2007	Fond du Lac	$ 740,712.00	40,535.90	$ 18.27	38.56%
2006	Thomson	$ 2,949,966.00	167,273.80	$ 17.64	26.30%	2006	Fond du Lac	$ 758,374.00	30,182.40	$ 25.13	28.71%

YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor	YEAR	PLANT	Total	Generation (MWh)	Cost per MWh	Capacity Factor
2016	Blanchard	$ 852,236.00	114,264.79	$ 7.46	72.47%	2016	Henn Is & Upper Dam	$ 1,115,921.00	93,577.89	$ 11.93	76.91%
2015	Blanchard	$ 809,015.00	85,855.10	$ 9.42	54.45%	2015	Henn Is & Upper Dam	$ 540,380.00	78,859.78	$ 6.85	64.81%
2014	Blanchard	$ 1,471,826.00	100,392.60	$ 14.66	63.67%	2014	Henn Is & Upper Dam	$ 1,196,507.00	61,666.85	$ 19.40	50.68%
2013	Blanchard	$ 2,142,931.00	86,962.60	$ 24.64	55.15%	2013	Henn Is & Upper Dam	$ 1,329,472.00	35,997.17	$ 36.93	29.58%
2012	Blanchard	$ 863,424.00	75,557.60	$ 11.43	47.92%	2012	Henn Is & Upper Dam	$ 1,194,320.00	47,317.28	$ 25.24	38.89%
2011	Blanchard	$ 532,035.00	94,490.60	$ 5.63	59.93%	2011	Henn Is & Upper Dam	$ 1,060,758.00	29,593.48	$ 35.84	24.32%
2010	Blanchard	$ 300,100.00	97,507.40	$ 3.08	61.84%	2010	Henn Is & Upper Dam	$ 1,178,010.00	60,408.25	$ 19.50	55.52%
2009	Blanchard	$ 325,824.00	83,571.20	$ 3.90	53.00%	2009	Henn Is & Upper Dam	$ 1,199,202.00	52,216.91	$ 22.97	48.00%
2008	Blanchard	$ 368,410.00	77,841.10	$ 4.73	49.37%	2008	Henn Is & Upper Dam	$ 1,332,386.00	44,090.00	$ 30.22	37.28%
2007	Blanchard	$ 407,254.00	71,574.30	$ 5.69	45.39%	2007	Henn Is & Upper Dam	$ 990,874.00	53,087.00	$ 18.67	44.89%
2006	Blanchard	$ 366,726.00	74,574.90	$ 4.92	47.29%	2006	Henn Is & Upper Dam	$ 1,058,328.00	58,997.00	$ 17.94	49.89%

Total Cost	$ 9,084,163.00
Total Gen	694,452.09
Cost per MWh	$ 13.08

2. Scenario Assumptions and Figures

Appendix XI: Scenario Assumptions

Electricity Demand Remains Flat

Electricity consumption throughout the United States has been flat since 2006, and increasing energy efficiency has reduced the demand for electricity in Minnesota. For the purposes of our study, we assume this trend remains constant and maintain current electricity demand throughout the report.

According to EIA data, Minnesota's total in-state generation was close to 60,000,000 megawatt hours in 2016 and 2017. We project these generation figures into the future, never going below 59,800,000 megawatt hours and never above 61,000,000 megawatt hours, acknowledging Minnesota will continue to import its remaining electricity use from other states and Canada.

Coal Plant Retirements

Renewable. In this scenario, Minnesota will continue to decommission its coal-fired power units, only at a more rapid rate compared to the retirement schedules laid out in utility resource plans in order to comply with the 50 percent renewable energy mandate by 2030. Under the mandate, we assume Units 1 and 2 (680 MW and 682 MW, respectively) at the Sherburne County generating station will be shuttered in 2026 and 2023, respectively, and the Allan S. King Plant (598 MW), Units 3 and 4 at the Clay Boswell Plant (355 MW and 585 MW), and Sherburne County Unit 3 will cease operations in 2028. Furthermore, this scenario continues the trend of utilizing existing coal plants less frequently as they approach their retirement age.

Short-Term Nuclear. Coal plant retirements in the Short-Term Nuclear scenario follow a similar timeline as they do in the Renewable scenario. Sherburne County Units 1 and 2 still retire in 2026 and 2023, respectively. Allan S. King, Clay Boswell Units 3 and 4, and Sherburne County Unit 3 all stop operating in 2030, rather than 2028, because we continue utilizing existing coal plants at higher capacity factors. Fully utilizing these resources prior to their retirement allows ratepayers to reap the financial benefits of using these retiring coal plants.

Long-Term Nuclear. The Long-Term Nuclear scenario differs from the Renewable and Short-Term Nuclear scenarios significantly. Instead of forcing the early retirement of existing coal plants, this scenario allows each plant to retire according to the retirement schedule laid out in utility resource plans. Sherburne County Units 1 and 2 still retire in 2026 and 2023, respectively, Sherburne County Unit 3 retires in 2037, Allan S. King retires in 2038, and Clay Boswell Units 3 and 4 retire in 2050.[40, 41]

ACE. The ACE scenario keeps all existing coal plants in operation through 2050 excluding Hoot Lake (130 MW), which has been reducing generation output since 2015 and its official retirement year is scheduled for 2021.[42] We upgraded each coal facility with upgrades laid out in the ACE Rule, resulting in a 4.5 percent heat rate improvement at $100 per kWh, which is the most expensive upgrade in the proposed rule.[43] Xcel Energy

Coal Plant	Renewable	Short-Term Nuclear	Long-Term Nuclear	ACE
Sherco Unit 1	Retires 2026	Retires 2026	Retires 2026	Upgrades 2026
Sherco Unit 2	Retires 2023	Retires 2023	Retires 2023	Upgrades 2023
Sherco Unit 3	Retires 2028	Retires 2030	Retires 2037	Upgrades 2037
AS King	Retires 2028	Retires 2030	Retires 2038	Upgrades 2038
Clay Boswell Units 3 and 4	Retires 2028	Retires 2030	Retires 2050	Upgrades 2050

Table 10. This table represents the retirement or upgrade schedule each scenario used for major coal plants supplying Minnesota with electricity.

laid out the requirements to keep the company's Sherco Units 1 and 2 online through 2040 with SCR upgrades, and these costs of installing this technology are also included in this scenario.[44]

Additional Installed Capacity. For the Renewable scenario, additional capacity installations were determined by utility filings from Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy.[45, 46,47,48] These filings projected capacity additions for combined cycle and combustion turbine natural gas facilities, wind farms, and solar projects generally through 2030. This scenario also includes the combined cycle natural gas plant that will be built in Becker, Minnesota.[49]

Wind and solar additions were required to meet current renewable energy mandates in Minnesota, and planned natural gas additions were deemed adequate to ensure reliability with growing amounts of intermittent resources being added to the grid. As Xcel noted in their Resource Plan:

"To reach 80 percent reduction [in carbon dioxide] implies…[b]ecoming more reliant on a single fuel (natural gas) to provide peaking power and support and balance high levels of intermittent renewable generation integration."[50]

The capacity additions laid out in utility filings were determined to be more than enough to meet a 50 percent renewable energy mandate, but not without first removing substantial coal capacity from the grid by 2028. Because this report seeks to understand the cost of complying with a 50 percent renewable energy standard by 2030, it assumes that no additional generation assets are necessary beyond the additions found in these filings, outside the repowering of retiring wind turbines.

For the Short-Term and Long-Term Nuclear scenarios, nuclear capacity is added to the grid according to the retirements of coal facilities, wind farms, solar fields, and biomass plants in each scenario.

Although the same amount of nuclear capacity is added in each nuclear scenario, the Long-Term Nuclear scenario has substantially lower costs than the Short-Term Nuclear scenario. This is because the Long-Term Nuclear scenario utilizes existing resources that are already depreciated. Doing so allows Minnesota ratepayers to take advantage of the lower costs associated with running depreciated assets, after taking into account system-wide expenses accounting for property taxes, transmission expenses, utility profit margins, and load balancing costs.

The ACE scenario does not add any new capacity and instead upgrades each coal plant as their retirement schedules laid out in utility resource planning require. This scenario also allows for the retirement of wind, solar, and biomass capacity. Because much of this capacity is intermittent in nature and built to satisfy renewable energy mandates and *not* to adequately meet electricity demand, no new capacity additions were required to meet Minnesota's electricity consumption requirements without these generation sources.

Nuclear Power Plants Remain Open. If the goal of energy policy in Minnesota is to reduce carbon dioxide emissions, shuttering Minnesota's existing nuclear power plants would be counterproduc-

Megawatts of Nuclear Added by Year	
Short-Term Nuclear	Long-Term Nuclear
1100 in 2026	800 in 2030
1000 in 2029	400 in 2031
1000 in 2030	900 in 2038
500 in 2036	1900 in 2050
400 in 2043	

Source Retirement Year		
Source	Short-Term Nuclear	Long-Term Nuclear
Coal	2030	2050
Wind	2036	2036
Solar	2048	2048
Biomass	2024	2024

Table 11. Additional nuclear capacity comes online in different years for our nuclear scenarios based primarily on the retirement schedules of coal facilities.

Scenario	Wind	Solar	Natural Gas	Nuclear
Renewable	3605	2481	3086	0
Short-Term Nuclear	0	0	786*	4000
Long-Term Nuclear	0	0	786*	4000
ACE	0	0	786*	0

*Table 12. This table shows the amount of capacity added for each power technology for all scenarios. *Natural gas capacity being added is already planned and not "additional" capacity intrinsic to the guidelines of these scenarios.*

tive. Therefore, we assume these plants will remain operational until 2050, requiring an additional $1.4 billion applied to each scenario to keep them in service.[51]

If the Monticello and Prairie Island nuclear facilities were forced to close to make way for more intermittent energy sources, Minnesota would need to invest even more money to replace them, and CO_2 emissions would increase substantially.

The Values Presented are Unsubsidized. Federal subsidies for wind and solar often hide the true cost for these sources of electricity generation. We present the data in this way for two main reasons: 1) It more accurately conveys the true cost of a 50 percent renewable energy mandate; 2) The wind Production Tax Credit (PTC) only lasts for 10 years. After this time, Minnesota ratepayers will pay the full and true cost of wind power.

Electric Car Penetration Remains Small. Battery-electric vehicle (BEV) sales were less than 1 percent of total U.S. vehicle sales in 2017. Electric vehicle growth has been most substantial in California, which requires auto manufacturers to build "zero-emission vehicles," or ZEVs, that have no tailpipe emissions. Minnesota does not have these standards and is therefore unlikely to see significant growth in electric vehicles.

Furthermore, Minnesota's climate adds additional challenges to electric vehicle ownership. For example, range for electric cars can drop by as much as 40 percent when temperatures reach 20 degrees above zero.[52] Minneapolis has 82 days per year on average when the minimum temperature drops to 20 degrees F.[53] During the winter of 2013-2014, Duluth experienced 60 days where the temperature dipped below zero.[54] Therefore, we assume that electric cars achieve only limited market penetration in Minnesota's automobile market by 2030, keeping electric demand from the transportation sector low.

Renewable Scenario-Specific Assumptions

50 Percent Renewable by 2030. The Renewable scenario requires that approximately 30,000,000 MWh of electricity be generated from renewable sources. However, this scenario does *not* require that the grid must be powered by at least 50 percent renewable energy at all times. We did not impose this criterion because doing so would exponentially increase the cost of the Renewable scenario by creating a need for battery storage and an even larger overbuild of wind and solar on the grid with subsequent curtailment of these resources when their generation would exceed the load of the system. This study assumes no curtailment, and thus represents a conservative cost estimate for the total cost of the Renewable scenario.[55]

Installed Solar Capacity Increases Seven-Fold. Resource planning documents from Xcel Energy, Otter Tail Power, Minnesota Power, and Great River Energy indicate plans to install 1,763 MW of additional solar capacity. These numbers are integrated into our cost assumptions.

The Renewable scenario also assumes all Community Solar installations in the project queue will be built. Solar generation will account for just over 9 percent of total generation by 2030 and continue through 2050.

Repowering Wind Turbines. For Minnesota electric utilities, 1,410.5 MW of existing wind facilities will need to be repowered in Minnesota from 2028 to 2036. However, these are only the wind farms that these utilities own. Wind farms across the state owned by Independent Power Producers (IPPs) will also need to be repowered, and the expenses will be recovered through power purchase agreement contracts with electric utilities like Xcel Energy and Minnesota Power. However, for this study, we assume investor-owned utilities will own all wind turbines. We assume a 44 percent capacity factor for repowered wind farms and use a capital cost of $1,716 per kilowatt, based on repowering projects that have already occurred. All facilities were assumed to have the same capacity factor and capital cost. Investor-owned utility capital expenses were subject to a 7.5 percent rate of return.

Example of the Lake Benton Wind Farm. Lake Benton was constructed in 1998 with the intention of operating for 30 years. However, twenty years later in 2018, the facility's operators filed for a repowering project with the Minnesota Public Utilities Commission.[56] (Repowering requires the decommissioning of wind turbines and replacing them with new ones.) The repowering project will involve replacing 137 wind turbines worth 100 MW of capacity with 44 new, larger, and more efficient wind turbines that will be worth the same 100 MW of capacity. This repowering project will require a capital cost of $170 million, in addition to the $3.3 million per year in operational and maintenance costs, and will generate no more than 438,000 MWh of electricity—or roughly .73 percent of Minnesota's annual generation.

Wind Farm	Year Constructed	Megawatts (MW)	Year Repowered
Ash Tabula	2008	48	2028
Taconite Ridge	2008	25	2028
Luverne	2009	49	2029
Langden	2009	40.5	2029
Bison	2010	497	2030
Nobles	2010	201	2030
Pleasant Valley	2015	200	2035
Borders	2015	150	2035
Courtenay	2016	200	2036

Table 13. This report utilizes information from FERC Form 1 filings for the year constructed and the capacity in megawatts (MWs) of each wind farm.

Expiration of Wind Production Tax Credit Frontloads the Costs. In the Renewable scenario, costs are highest in the early years because utility companies will seek to take advantage of the wind Production Tax Credit. Xcel Energy has stated they will build 1,800 MW of wind power regardless of whether the wind Production Tax Credit is extended. In the event the tax credits expire, Xcel has stated they will accelerate wind turbine construction to capture the federal tax credits.[57] However, the tax credits for all wind farms expire after 10 years.

Renewable Scenario with No Nuclear. To accompany our Renewable scenario, we conducted a partial scenario of what would happen if Xcel Energy's two nuclear plants, Monticello and Prairie Island, were not allowed to upgrade and extend their lifespans through 2050.

If Minnesota's nuclear capacity does not extend to 2050, carbon dioxide emissions will increase substantially compared to keeping these facilities open, increasing from 5.4 million metric tons of CO_2 to more than 12.4 million metric tons per year. That would be more than double the amount of CO_2 metric tons emitted when nuclear capacity stays online. Emissions increase so significantly because nuclear power produces carbon-free electricity, and retiring these facilities will require much, if not all, of the lost generation to be replaced by natural gas generation, unless Minnesota invested more money in new wind and solar facilities.

If wind energy was relied upon to replace the entire nuclear generation lost, Minnesota would need roughly 3,600 MWs of additional wind capacity to generate the same annual generation, totaling nearly $5.9 billion dollars in capital costs alone.[58] Additionally, investing in new

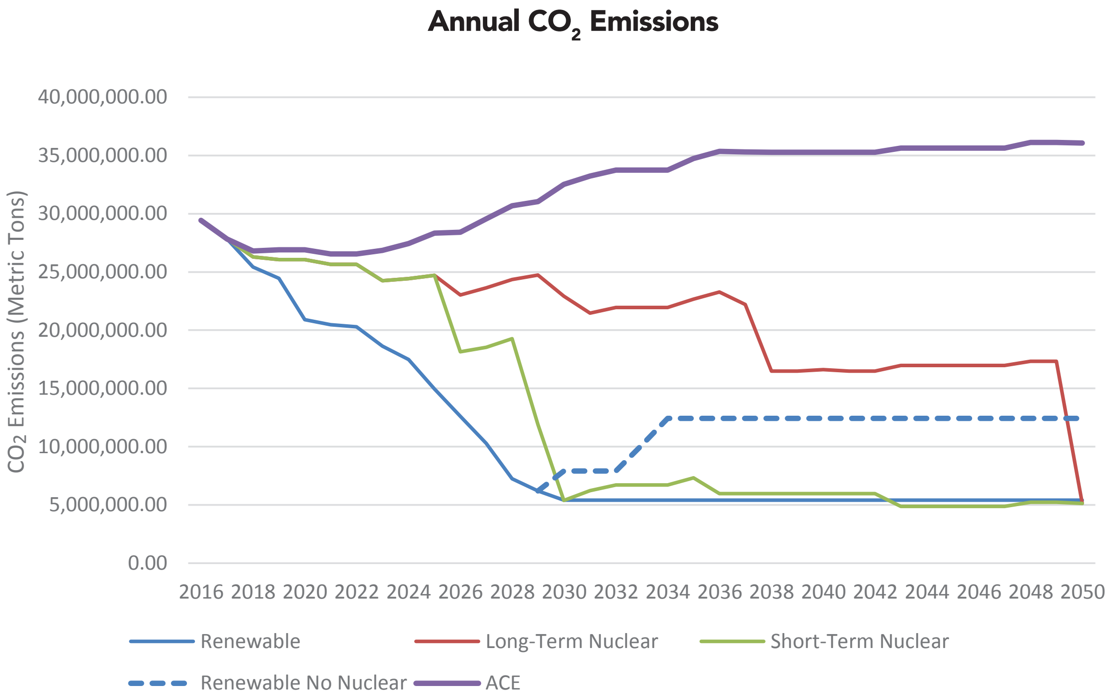

Figure 38. The dotted line represents the annual CO_2 emission increase by retiring Minnesota's nuclear capacity. The rise corresponds with higher amounts of natural gas being used to replace the carbon-free generation lost.

combined cycle and combustion turbine natural gas power facilities would be required to adequately meet electricity demand during peak hours in the summer when the wind isn't blowing and the sun isn't shining, with the loss of significant baseload nuclear generation.

Furthermore, the cost to reduce each metric ton of CO_2 would increase and become harder to achieve. This is discussed further in Appendix XV.

Appendix XII: Annual Generation Data by Source

The following tables detail total annual generation for each scenario and generation by source in megawatt hours (MWh).

Renewable Scenario (MWhs)

Energy Source	2016	2017	2018	2019	2020	2021	2022	2023	2024
All Sources	59,478,753	58,748,841	59,870,468	60,006,557	59,976,983	60,053,371	59,859,529	59,979,927	60,073,720
Coal	23,206,289	22,781,898	19,559,766	17,600,031	14,666,693	14,211,173	14,211,173	11,821,445	10,343,764
Hydroelectric	1,208,502	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702
Natural Gas (CT)	852,663	643,929	1,066,898	1,333,622	1,066,898	1,153,797	865,348	1,153,797	1,153,797
Natural Gas (CC)	8,075,413	6,063,663	7,606,764	9,508,454	9,033,032	9,033,032	9,033,032	10,459,300	11,351,628
Nuclear	13,860,816	13,904,351	13,932,000	13,932,000	13,932,000	13,932,000	13,932,000	13,932,000	13,932,000
Utility Scale Solar	10,107	596,124	797,230	797,230	844,534	844,534	844,534	844,534	1,002,214
Community Solar			760,018	854,626	949,234	1,043,842	1,138,450	1,233,058	1,327,666
Biomass	674,321	636,893	636,000	468,800	468,800	468,800	468,800	468,800	468,800
Wind	9,933,487	11,137,272	12,519,091	12,519,091	16,023,091	16,373,491	16,373,491	17,074,291	17,501,148
Other	1,657,154	1,727,009	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2025	2026	2027	2028	2029	2030	2031	2032	2033
All Sources	60,049,569	60,092,983	60,024,533	60,035,290	60,065,257	59,937,886	59,937,886	59,937,886	59,937,886
Coal	8,866,084	7,079,044	4,719,362	-	-	-	-	-	-
Hydroelectric	1,257,702	1,257,702	1,257,702	1,257,702	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	1,095,561	1,614,223	1,690,960	2,209,622	2,651,547	2,209,622	2,209,622	2,209,622	2,209,622
Natural Gas (CC)	9,503,689	7,988,279	8,321,124	11,649,574	8,986,814	7,988,279	7,988,279	7,988,279	7,988,279
Nuclear	13,932,000	13,932,000	13,932,000	13,932,000	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	1,632,934	2,158,008	2,473,368	3,261,768	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128
Community Solar	1,422,274	1,516,882	1,611,490	1,706,098	1,800,706	1,892,160	1,892,160	1,892,160	1,892,160
Biomass	468,800	468,800	468,800	468,800	468,800	468,800	468,800	636,333	636,333
Wind	20,135,526	22,343,046	23,814,726	23,814,726	25,654,326	26,875,960	26,875,960	26,875,960	26,875,960
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2034	2035	2036	2037	2038	2039	2040	2041	2042
All Sources	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886
Coal	-	-	-	-	-	-	-	-	-
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622
Natural Gas (CC)	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279
Nuclear	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128
Community Solar	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160
Biomass	636,333	636,333	636,333	636,333	636,333	636,333	636,333	636,333	636,333
Wind	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2043	2044	2045	2046	2047	2048	2049	2050	
All Sources	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	59,937,886	
Coal	-	-	-	-	-	-	-	-	
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	
Natural Gas (CT)	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	2,209,622	
Natural Gas (CC)	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	7,988,279	
Nuclear	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	
Utility Scale Solar	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	3,577,128	
Community Solar	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	1,892,160	
Biomass	636,333	636,333	636,333	636,333	636,333	636,333	636,333	636,333	
Wind	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	26,875,960	
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	

Short-Term Nuclear Scenario (MWhs)

Energy Source	2016	2017	2018	2019	2020	2021	2022	2023	2024
All Sources	59,478,753	58,748,841	59,951,910	59,935,680	59,935,680	59,802,388	59,802,388	59,957,335	59,997,789
Coal	23,206,289	22,781,898	21,124,547	20,533,370	20,533,370	19,895,642	19,895,642	16,550,023	16,550,023
Hydroelectric	1,208,502	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702
Natural Gas (CT)	852,663	643,929	533,449	800,173	800,173	1,066,898	1,066,898	1,867,071	1,187,768
Natural Gas (CC)	8,075,413	6,063,663	6,655,918	7,131,341	7,131,341	7,369,052	7,369,052	10,697,011	11,885,568
Nuclear	13,860,816	13,904,351	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	10,107	596,124	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar			760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	674,321	636,893	636,000	468,800	468,800	468,800	468,800	468,800	-
Wind	9,933,487	11,137,272	12,519,091	12,519,091	12,519,091	12,519,091	12,519,091	11,891,525	11,891,525
Other	1,657,154	1,727,009	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2025	2026	2027	2028	2029	2030	2031	2032	2033
All Sources	59,894,508	59,957,125	59,939,850	59,942,268	60,033,722	59,814,440	59,897,695	59,939,008	59,939,008
Coal	16,550,023	13,214,215	13,214,215	13,214,215	6,665,239	-	-	-	-
Hydroelectric	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	1,900,429	931,538	745,231	745,231	558,923	372,615	558,923	558,923	558,923
Natural Gas (CC)	11,555,631	6,830,067	7,805,791	9,269,376	8,781,515	10,245,100	11,708,686	12,684,410	12,684,410
Nuclear	13,932,955	23,424,941	23,685,218	23,685,218	31,656,818	39,628,418	39,628,418	39,628,418	39,628,418
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	-	-	-	-	-	-	-	-	-
Wind	11,405,520	11,006,414	9,939,446	8,478,278	7,821,278	5,018,078	3,451,440	2,517,028	2,517,028
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2034	2035	2036	2037	2038	2039	2040	2041	2042
All Sources	59,939,008	59,932,262	59,886,570	59,886,570	59,886,570	59,886,570	59,886,570	59,886,570	59,886,570
Coal	-	-	-	-	-	-	-	-	-
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	558,923	558,923	745,231	745,231	745,231	745,231	745,231	745,231	745,231
Natural Gas (CC)	12,684,410	13,904,065	10,976,893	10,976,893	10,976,893	10,976,893	10,976,893	10,976,893	10,976,893
Nuclear	39,628,418	39,628,418	43,614,218	43,614,218	43,614,218	43,614,218	43,614,218	43,614,218	43,614,218
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	-	-	-	-	-	-	-	-	-
Wind	2,517,028	1,290,628	-	-	-	-	-	-	-
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2043	2044	2045	2046	2047	2048	2049	2050	
All Sources	60,004,567	60,004,567	60,004,567	60,004,567	60,004,567	59,996,753	59,996,753	59,925,692	
Coal	-	-	-	-	-	-	-	-	
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	
Natural Gas (CT)	1,117,846	1,117,846	1,117,846	1,117,846	1,117,846	931,538	931,538	372,615	
Natural Gas (CC)	8,293,653	8,293,653	8,293,653	8,293,653	8,293,653	9,269,376	9,269,376	9,757,238	
Nuclear	46,802,858	46,802,858	46,802,858	46,802,858	46,802,858	46,802,858	46,802,858	46,802,858	
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	-	-	-	
Community Solar	-	-	-	-	-	-	-	-	
Biomass	-	-	-	-	-	-	-	-	
Wind	-	-	-	-	-	-	-	-	
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	

Long-Term Nuclear Scenario (MWhs)

Energy Source	2016	2017	2018	2019	2020	2021	2022	2023	2024
All Sources	59,478,753	58,748,841	59,951,910	59,935,680	59,935,680	59,802,388	59,802,388	59,957,335	59,997,789
Coal	23,206,289	22,781,898	21,124,547	20,533,370	20,533,370	19,895,642	19,895,642	16,550,023	16,550,023
Hydroelectric	1,208,502	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702
Natural Gas (CT)	852,663	643,929	533,449	800,173	800,173	1,066,898	1,066,898	1,867,071	1,187,768
Natural Gas (CC)	8,075,413	6,063,663	6,655,918	7,131,341	7,131,341	7,369,052	7,369,052	10,697,011	11,885,568
Nuclear	13,860,816	13,904,351	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	10,107	596,124	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar			760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	674,321	636,893	636,000	468,800	468,800	468,800	468,800	468,800	-
Wind	9,933,487	11,137,272	12,519,091	12,519,091	12,519,091	12,519,091	12,519,091	11,891,525	11,891,525
Other	1,657,154	1,727,009	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027

Energy Source	2025	2026	2027	2028	2029	2030	2031	2032	2033
All Sources	59,894,508	59,934,261	59,971,702	59,858,873	59,876,321	59,831,943	59,988,379	60,029,691	60,029,691
Coal	16,550,023	13,214,215	13,214,215	13,214,215	13,214,215	13,214,215	13,214,215	13,214,215	13,214,215
Hydroelectric	1,257,702	1,257,702	1,257,702	1,257,702	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	1,900,429	1,863,077	2,235,692	2,608,308	2,794,615	1,304,154	1,117,846	1,117,846	1,117,846
Natural Gas (CC)	11,555,631	15,367,650	16,099,443	17,075,167	17,563,029	15,855,512	13,172,272	14,147,996	14,147,996
Nuclear	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	19,889,755	24,482,378	24,482,378	24,482,378
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	-	-	-	-	-	-	-	-	-
Wind	11,405,520	11,006,414	9,939,446	8,478,278	7,821,278	5,018,078	3,451,440	2,517,028	2,517,028
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027

Energy Source	2034	2035	2036	2037	2038	2039	2040	2041	2042
All Sources	60,029,691	60,036,384	59,965,410	59,917,405	59,844,662	59,844,662	60,030,970	59,844,662	59,844,662
Coal	13,214,215	13,214,215	13,214,215	11,201,324	7,883,912	7,883,912	7,883,912	7,883,912	7,883,912
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	1,117,846	1,863,077	1,863,077	2,608,308	1,117,846	1,117,846	1,304,154	1,117,846	1,117,846
Natural Gas (CC)	14,147,996	14,635,858	15,855,512	17,075,167	14,635,858	14,635,858	14,635,858	14,635,858	14,635,858
Nuclear	24,482,378	24,482,378	24,482,378	24,482,378	31,656,818	31,656,818	31,656,818	31,656,818	31,656,818
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	-	-	-	-	-	-	-	-	-
Wind	2,517,028	1,290,628	-	-	-	-	-	-	-
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027

Energy Source	2043	2044	2045	2046	2047	2048	2049	2050
All Sources	59,945,122	59,945,122	59,945,122	59,945,122	59,945,122	59,879,685	59,879,685	59,925,692
Coal	7,883,912	7,883,912	7,883,912	7,883,912	7,883,912	7,883,912	7,883,912	-
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	1,490,461	1,490,461	1,490,461	1,490,461	1,490,461	1,490,461	1,490,461	372,615
Natural Gas (CC)	15,123,720	15,123,720	15,123,720	15,123,720	15,123,720	15,855,512	15,855,512	9,757,238
Nuclear	31,656,818	31,656,818	31,656,818	31,656,818	31,656,818	31,656,818	31,656,818	46,802,858
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	-	-	-
Community Solar	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027

Affordable Clean Energy Scenario (MWhs)

Energy Source	2016	2017	2018	2019	2020	2021	2022	2023	2024
All Sources	59,478,753	58,748,841	60,050,180	59,976,082	59,976,082	60,005,936	60,005,936	60,091,503	60,008,038
Coal	23,206,289	22,781,898	21,906,938	22,000,039	22,000,039	21,316,759	21,316,759	21,316,759	22,027,318
Hydroelectric	1,208,502	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702	1,257,702
Natural Gas (CT)	852,663	643,929	800,173	800,173	800,173	800,173	800,173	800,173	712,661
Natural Gas (CC)	8,075,413	6,063,663	5,705,073	5,705,073	5,705,073	6,418,207	6,418,207	7,131,341	6,893,629
Nuclear	13,860,816	13,904,351	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	10,107	596,124	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar			760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	674,321	636,893	636,000	468,800	468,800	468,800	468,800	468,800	-
Wind	9,933,487	11,137,272	12,519,091	12,519,091	12,519,091	12,519,091	12,519,091	11,891,525	11,891,525
Other	1,657,154	1,727,009	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2025	2026	2027	2028	2029	2030	2031	2032	2033
All Sources	60,091,109	59,971,465	59,970,335	59,951,518	60,026,590	60,092,938	59,932,262	60,031,198	60,031,198
Coal	23,093,156	23,093,156	24,158,994	24,869,552	24,869,552	24,869,552	24,869,552	24,869,552	24,869,552
Hydroelectric	1,257,702	1,257,702	1,257,702	1,257,702	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	712,661	558,923	558,923	558,923	558,923	745,231	931,538	745,231	745,231
Natural Gas (CC)	6,396,867	6,830,067	6,830,067	7,561,860	8,293,653	10,976,893	12,196,548	13,416,203	13,416,203
Nuclear	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	-	-	-	-	-	-	-	-	-
Wind	11,405,520	11,006,414	9,939,446	8,478,278	7,821,278	5,018,078	3,451,440	2,517,028	2,517,028
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2034	2035	2036	2037	2038	2039	2040	2041	2042
All Sources	60,031,198	60,003,218	59,932,245	59,932,245	59,932,245	59,932,245	59,932,245	59,932,245	59,932,245
Coal	24,869,552	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981
Natural Gas (CT)	745,231	745,231	745,231	745,231	745,231	745,231	745,231	745,231	745,231
Natural Gas (CC)	13,416,203	13,904,065	15,123,720	15,123,720	15,123,720	15,123,720	15,123,720	15,123,720	15,123,720
Nuclear	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230	797,230
Community Solar	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018	760,018
Biomass	-	-	-	-	-	-	-	-	-
Wind	2,517,028	1,290,628	-	-	-	-	-	-	-
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027
Energy Source	2043	2044	2045	2046	2047	2048	2049	2050	
All Sources	59,904,020	59,904,020	59,904,020	59,904,020	59,904,020	60,024,891	60,024,891	60,024,890.60	
Coal	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111	25,580,111.04	
Hydroelectric	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,981	1,257,980.68	
Natural Gas (CT)	745,231	745,231	745,231	745,231	745,231	931,538	931,538	931,538.40	
Natural Gas (CC)	15,855,512	15,855,512	15,855,512	15,855,512	15,855,512	16,587,305	16,587,305	16,587,305.28	
Nuclear	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955	13,932,955.20	
Utility Scale Solar	797,230	797,230	797,230	797,230	797,230	-	-	-	
Community Solar	-	-	-	-	-	-	-	-	
Biomass	-	-	-	-	-	-	-	-	
Wind	-	-	-	-	-	-	-	-	
Other	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	1,732,027	

Appendix XIII: Annual Installed Capacity Data by Source

The following tables show the annual capacity in megawatts (MW) for each generation resource and annual total installed capacity for each scenario.

Renewable Scenario (MWs)

Capacity	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
All Sources	17,680	18,104	18,396	18,121	19,211	19,489	19,549	19,127	19,587	21,523
Coal	4,656	4,656	4,466	4,186	4,186	4,056	4,056	3,374	3,374	3,374
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	3,045	3,045	3,045	3,045	3,045	3,293	3,293	3,293	3,293	4,169
Natural Gas (CC)	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	3,014	3,014
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,316	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Biomass	212	212	212	157	157	157	157	157	157	157
Utility Scale Solar	256	506	506	506	536	536	536	536	636	1,036
Community Solar	42	288	482	542	602	662	722	782	842	902
Wind	3,368	3,573	3,573	3,573	4,573	4,673	4,673	4,873	4,873	5,473
Capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
All Sources	23,060	23,939	24,718	24,143	22,846	22,846	22,846	22,846	22,846	22,846
Coal	2,694	2,694	2,694	0	0	0	0	0	0	0
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	4,607	4,826	5,045	5,045	5,045	5,045	5,045	5,045	5,045	5,045
Natural Gas (CC)	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Biomass	157	157	157	157	157	157	157	157	157	157
Utility Scale Solar	1,369	1,569	2,069	2,269	2,269	2,269	2,269	2,269	2,269	2,269
Community Solar	962	1,022	1,082	1,142	1,200	1,200	1,200	1,200	1,200	1,200
Wind	6,073	6,473	6,473	6,973	6,973	6,973	6,973	6,973	6,973	6,973
Capacity	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
All Sources	22,846	22,846	22,846	22,846	22,846	22,846	22,846	22,846	22,846	22,846
Coal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	5,045	5,045	5,045	5,045	5,045	5,045	5,045	5,045	5,045	5,045
Natural Gas (CC)	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Biomass	157	157	157	157	157	157	157	157	157	157
Utility Scale Solar	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,269
Community Solar	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Wind	6,973	6,973	6,973	6,973	6,973	6,973	6,973	6,973	6,973	6,973
Capacity	2046	2047	2048	2049	2050					
All Sources	22,846	22,846	22,846	22,846	22,846					
Coal	0	0	0	0	0					
Hydroelectric	215	215	215	215	215					
Natural Gas (CT)	5,045	5,045	5,045	5,045	5,045					
Natural Gas (CC)	3,800	3,800	3,800	3,800	3,800					
Nuclear	1,871	1,871	1,871	1,871	1,871					
Other	1,312	1,312	1,312	1,312	1,312					
Biomass	157	157	157	157	157					
Utility Scale Solar	2,269	2,269	2,269	2,269	2,269					
Community Solar	1,200	1,200	1,200	1,200	1,200					
Wind	6,973	6,973	6,973	6,973	6,973					

Short-Term Nuclear Scenario (MWs)										
Capacity	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
All Sources	17,680	18,104	18,396	18,061	18,061	17,931	17,931	17,070	16,579	16,082
Coal	4,656	4,656	4,466	4,186	4,186	4,056	4,056	3,374	3,374	3,374
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	3,045	3,045	3,045	3,045	3,045	3,045	3,045	3,045	2,712	2,712
Natural Gas (CC)	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,356
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,316	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Other Biomass	212	212	212	157	157	157	157	157	-	-
Utility Scale Solar	256	506	506	506	506	506	506	506	506	506
Community Solar	42	288	482	482	482	482	482	482	482	482
Wind	3,368	3,573	3,573	3,573	3,573	3,573	3,573	3,394	3,394	3,255
Capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
All Sources	16,233	15,928	15,511	14,989	13,830	13,383	13,116	13,116	13,116	12,766
Coal	2,694	2,694	2,694	1,359	-	-	-	-	-	-
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785
Nuclear	2,971	2,971	2,971	3,971	4,971	4,971	4,971	4,971	4,971	4,971
Other	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Other Biomass	-	-	-	-	-	-	-	-	-	-
Utility Scale Solar	506	506	506	506	506	506	506	506	506	506
Community Solar	482	482	482	482	482	482	482	482	482	482
Wind	3,141	2,837	2,420	2,232	1,432	985	718	718	718	368
Capacity	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
All Sources	12,898	12,898	12,898	12,898	12,898	12,898	12,898	12,816	12,816	12,816
Coal	-	-	-	-	-	-	-	-	-	-
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785
Nuclear	5,471	5,471	5,471	5,471	5,471	5,471	5,471	5,871	5,871	5,871
Other	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Other Biomass	-	-	-	-	-	-	-	-	-	-
Utility Scale Solar	506	506	506	506	506	506	506	506	506	506
Community Solar	482	482	482	482	482	482	482	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-
Capacity	2046	2047	2048	2049	2050					
All Sources	12,816	12,816	12,310	12,310	12,310					
Coal	-	-	-	-	-					
Hydroelectric	215	215	215	215	215					
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127					
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785					
Nuclear	5,871	5,871	5,871	5,871	5,871					
Other	1,312	1,312	1,312	1,312	1,312					
Other Biomass	-	-	-	-	-					
Utility Scale Solar	506	506	-	-	-					
Community Solar	-	-	-	-	-					
Wind	-	-	-	-	-					

Long-Term Nuclear Scenario (MWs)

Capacity	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
All Sources	17,680	18,104	18,396	18,061	18,061	17,931	17,931	17,070	16,579	16,082
Coal	4,656	4,656	4,466	4,186	4,186	4,056	4,056	3,374	3,374	3,374
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	3,045	3,045	3,045	3,045	3,045	3,045	3,045	3,045	2,712	2,712
Natural Gas (CC)	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,356
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,316	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Biomass	212	212	212	157	157	157	157	157	0	0
Utility Scale Solar	42	288	482	482	482	482	482	482	482	482
Community Solar	256	506	506	506	506	506	506	506	506	506
Wind	3,368	3,573	3,573	3,573	3,573	3,573	3,573	3,394	3,394	3,255
Capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
All Sources	15,133	14,828	14,411	14,224	14,224	14,176	13,910	13,910	13,910	13,560
Coal	2,694	2,694	2,694	2,694	2,694	2,694	2,694	2,694	2,694	2,694
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785
Nuclear	1,871	1,871	1,871	1,871	2,671	3,071	3,071	3,071	3,071	3,071
Other	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Biomass	0	0	0	0	0	0	0	-	0	0
Utility Scale Solar	482	482	482	482	482	482	482	482	482	482
Community Solar	506	506	506	506	506	506	506	506	506	506
Wind	3,141	2,837	2,420	2,232	1,432	985	718	718	718	368
Capacity	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
All Sources	13,191	12,324	12,683	12,683	12,683	12,683	12,683	12,201	12,201	12,201
Coal	2,694	1,827	1,286	1,286	1,286	1,286	1,286	1,286	1,286	1,286
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785
Nuclear	3,071	3,071	3,971	3,971	3,971	3,971	3,971	3,971	3,971	3,971
Other	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Biomass	0	0	0	0	0	0	0	-	0	0
Utility Scale Solar	482	482	482	482	482	482	482	-	0	0
Community Solar	506	506	506	506	506	506	506	506	506	506
Wind	0	0	0	0	0	0	0	-	0	0
Capacity	2046	2047	2048	2049	2050					
All Sources	12,201	12,201	11,696	11,696	12,310					
Coal	1,286	1,286	1,286	1,286	0					
Hydroelectric	215	215	215	215	215					
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127					
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785					
Nuclear	3,971	3,971	3,971	3,971	5,871					
Other	1,312	1,312	1,312	1,312	1,312					
Biomass	0	0	0	0	0					
Utility Scale Solar	0	0	0	0	0					
Community Solar	506	506	0	0	0					
Wind	0	0	0	0	0					

Affordable Clean Energy Scenario (MWs)										
Capacity	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
All Sources	17,680	18,104	18,396	18,061	18,061	17,931	17,931	17,752	17,261	16,764
Coal	4,656	4,656	4,466	4,186	4,186	4,056	4,056	4,056	4,056	4,056
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	3,045	3,045	3,045	3,045	3,045	3,045	3,045	3,045	2,712	2,712
Natural Gas (CC)	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,356
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,312	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Other Biomass	212	212	212	157	157	157	157	157	-	-
Community Solar	42	288	482	482	482	482	482	482	482	482
Utility Scale Solar	256	506	506	506	506	506	506	506	506	506
Wind	3,368	3,573	3,573	3,573	3,573	3,573	3,573	3,394	3,394	3,255
Capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
All Sources	16,495	16,190	15,773	15,586	14,786	14,338	14,072	14,072	14,072	13,722
Coal	4,056	4,056	4,056	4,056	4,056	4,056	4,056	4,056	4,056	4,056
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Other Biomass	-	-	-	-	-	-	-	-	-	-
Community Solar	482	482	482	482	482	482	482	482	482	482
Utility Scale Solar	506	506	506	506	506	506	506	506	506	506
Wind	3,141	2,837	2,420	2,232	1,432	985	718	718	718	368
Capacity	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
All Sources	13,353	13,353	13,353	13,353	13,353	13,353	13,353	12,871	12,871	12,871
Coal	4,056	4,056	4,056	4,056	4,056	4,056	4,056	4,056	4,056	4,056
Hydroelectric	215	215	215	215	215	215	215	215	215	215
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127	2,127
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785
Nuclear	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871	1,871
Other	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Other Biomass	-	-	-	-	-	-	-	-	-	-
Community Solar	482	482	482	482	482	482	482	-	-	-
Utility Scale Solar	506	506	506	506	506	506	506	506	506	506
Wind	-	-	-	-	-	-	-	-	-	-
Capacity	2046	2047	2048	2049	2050					
All Sources	12,871	12,871	12,366	12,366	12,366					
Coal	4,056	4,056	4,056	4,056	4,056					
Hydroelectric	215	215	215	215	215					
Natural Gas (CT)	2,127	2,127	2,127	2,127	2,127					
Natural Gas (CC)	2,785	2,785	2,785	2,785	2,785					
Nuclear	1,871	1,871	1,871	1,871	1,871					
Other	1,316	1,316	1,316	1,316	1,316					
Other Biomass	-	-	-	-	-					
Community Solar	-	-	-	-	-					
Utility Scale Solar	506	506	-	-	-					
Wind	-	-	-	-	-					

Appendix XIV: Annual Capacity Factors by Source

The following tables detail annual capacity factors for each scenario, determined by either technology limitations, in the case of wind, solar, and nuclear, or generation needs, in the case of natural gas and coal. For the purpose of simplicity, hydroelectric generation was kept constant at 67 percent.

Renewables	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	50%	48%	40%	40%	40%	40%	35%	30%	30%	20%	0%	0%	0%	0%	0%	0%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	4%	5%	4%	4%	3%	4%	4%	3%	4%	4%	5%	6%	5%	5%	5%	5%
Natural Gas (CC)	32%	40%	38%	38%	38%	44%	43%	36%	24%	25%	35%	27%	24%	24%	24%	24%
Nuclear	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	41%	42%	42%	42%	42%	42%	44%	44%	44%	44%

Long-Term Nuclear	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	54%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	2%	3%	3%	4%	4%	7%	5%	8%	10%	12%	14%	15%	7%	6%	6%	6%
Natural Gas (CC)	28%	30%	30%	31%	31%	45%	50%	56%	63%	66%	70%	72%	65%	54%	58%	58%
Nuclear	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	90%	91%	91%	91%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Short-Term Nuclear	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	55%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	0%	0%	0%	0%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	2%	3%	3%	4%	4%	7%	5%	8%	5%	4%	4%	3%	2%	3%	3%	3%
Natural Gas (CC)	40%	40%	28%	30%	30%	31%	31%	45%	50%	56%	28%	32%	38%	36%	42%	48%
Nuclear	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	90%	91%	91%	91%	91%	91%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

ACE	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	56%	60%	60%	60%	60%	60%	62%	65%	65%	68%	70%	70%	70%	70%	70%	70%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	5%	4%	4%
Natural Gas (CC)	24%	24%	24%	27%	27%	30%	29%	31%	28%	28%	31%	34%	45%	50%	55%	55%
Nuclear	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Renewables	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Coal	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Natural Gas (CC)	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Nuclear	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%

Long-Term Nuclear	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Coal	56%	56%	56%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	0%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	6%	10%	10%	14%	6%	6%	7%	6%	6%	8%	8%	8%	8%	8%	8%	8%	2%
Natural Gas (CC)	58%	60%	65%	70%	60%	60%	60%	60%	60%	62%	62%	62%	62%	62%	65%	65%	40%
Nuclear	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Short-Term Nuclear	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Coal	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	3%	3%	4%	4%	4%	4%	4%	4%	4%	6%	6%	6%	6%	6%	5%	5%	2%
Natural Gas (CC)	52%	52%	52%	57%	45%	45%	45%	45%	45%	45%	45%	34%	34%	34%	34%	34%	38%
Nuclear	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

ACE	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Coal	70%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%
Hydroelectric	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Natural Gas (CT)	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	5%	5%	5%
Natural Gas (CC)	55%	57%	62%	62%	62%	62%	62%	62%	62%	65%	65%	65%	65%	65%	68%	68%	68%
Nuclear	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Solar	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Wind	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Appendix XV: Annual CO_2 Emissions and Cost per Metric Ton CO_2 Averted

The following values were used to calculate annual emissions, based on EIA data for annual emissions in Minnesota.[59]

Power Source	Metric Tons per MWh
Coal	1.07
Natural Gas (CC)	0.50
Natural Gas (CT)	0.64

Table 14. Electricity generation produced by coal plants emits significantly more CO_2 than natural gas.

This report includes the cost to reduce each metric ton of CO_2 for each scenario, as well as the savings per metric ton of CO_2 increased for the ACE scenario. These figures were determined by dividing the total additional cost resulting in each scenario by the total amount of CO_2 emissions averted compared to 2016 levels extended to 2050. For the ACE scenario, we calculated the savings per CO_2 increase by dividing the total amount saved by the total CO_2 emissions increased from 2016 levels.

The calculation formulas for the cost per metric ton of CO_2 averted and savings per metric ton of CO_2 increased are found in Table 15.

Cost per Metric Ton CO_2 Averted vs. Savings per Metric Ton CO_2 Increase

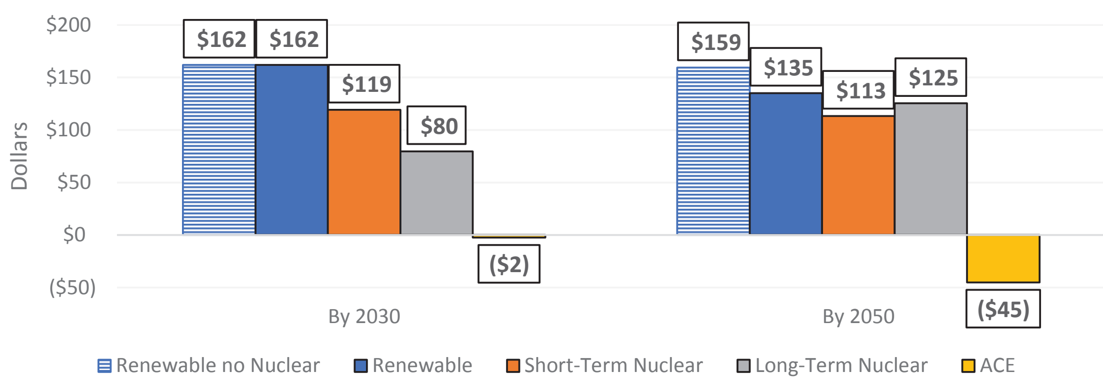

Figure 39. If Minnesota's two nuclear power plants retire, the cost per metric ton averted increases by more than $20 per metric ton of carbon dioxide. Nuclear power is extremely effective in reducing carbon emissions and is by far one of the most successful sources of electricity in doing so around the world. Retiring Minnesota's nuclear facilities would greatly harm the state's efforts to reduce CO_2 emissions.

Cost per Metric Ton CO2 Averted

2016 Emission Levels Extend Through 2050	-	Scenario Emissions through 2050	=	Emissions Averted
Total Additional Scenario Costs	/	Emission Averted	=	Cost per Metric Ton CO2 Averted

Savings per Metric Ton CO2 Increase

Scenario Emissions through 2050	-	2016 Emission Levels Extend Through 2050	=	Emissions Increased
Total Additional Scenario Costs	/	Emission Increased	=	Savings per Metric Ton CO2 Increase

Table 15. The cost per metric ton of CO_2 averted was calculated for the Renewable and nuclear scenarios, compared to the savings per metric ton of CO_2 increased for the ACE scenario.

The following tables detail annual CO_2 emissions in metric tons for each scenario. The nuclear and Renewable scenarios all reduced emissions to nearly 5,000,000 metric tons by 2050, but this was achieved at different costs.

	2016	2017	2018	2019	2020
Renewable	29,422,375	27,826,743	25,421,681	24,447,947	20,901,379
Long-Term Nuclear	29,422,375	27,826,743	26,280,204	26,055,540	26,055,540
Short-Term Nuclear	29,422,375	27,826,743	26,280,204	26,055,540	26,055,540
ACE	29,422,375	27,826,743	26,809,972	26,909,590	26,909,590

2021	2022	2023	2024	2025	2026	2027
20,469,185	20,285,914	18,627,462	17,493,855	14,948,977	12,606,393	10,297,215
25,661,853	25,661,853	24,259,445	24,423,911	24,711,246	23,029,960	23,633,708
25,661,853	25,661,853	24,259,445	24,423,911	24,711,246	18,156,418	18,527,378
26,536,124	26,536,124	26,855,524	27,441,005	28,332,321	28,413,540	29,553,986

2028	2029	2030	2031	2032	2033	2034
7,246,285	6,191,671	5,410,113	5,410,113	5,410,113	5,410,113	5,410,113
24,359,790	24,722,830	22,919,507	21,455,464	21,944,798	21,944,798	21,944,798
19,261,380	11,890,935	5,374,757	6,227,132	6,716,466	6,716,466	6,716,466
30,681,285	31,048,285	32,512,328	33,242,370	33,735,664	33,735,664	33,735,664

2035	2036	2037	2038	2039	2040	2041
5,410,113	5,410,113	5,410,113	5,410,113	5,410,113	5,410,113	5,410,113
22,662,960	23,274,628	22,205,997	16,486,042	16,486,042	16,604,416	16,486,042
7,328,134	5,978,505	5,978,505	5,978,505	5,978,505	5,978,505	5,978,505
34,740,629	35,352,297	35,303,031	35,269,288	35,269,288	35,269,288	35,269,288

2042	2043	2044	2045	2046	2047	2048
5,410,113	5,410,113	5,410,113	5,410,113	5,410,113	5,410,113	5,410,113
16,486,042	16,967,456	16,967,456	16,967,456	16,967,456	16,967,456	17,334,457
5,978,505	4,869,583	4,869,583	4,869,583	4,869,583	4,869,583	5,240,544
35,269,288	35,636,288	35,636,288	35,636,288	35,636,288	35,636,288	36,121,663

2049	2050
5,410,113	5,410,113
17,334,457	5,130,090
5,240,544	5,130,090
36,121,663	36,068,798

Appendix XVI: Annual Additional Rate Base and Utility Profit Depreciation Schedule

The following table details the annual additional rate base and utility profit for each scenario. These figures follow the depreciation schedules for the capacity installed or upgraded in each scenario.

Additional Rate Base and Utility Profit Depreciation

Renewable	2017	2018	2019	2020	2021	2022	2023	2024
Total Rate Base:	$ 940,537,600.00	$ 899,581,116.00	$ 858,624,632.00	$ 7,361,644,632.00	$ 9,245,203,832.00	$ 8,986,470,014.67	$ 9,035,141,183.04	$ 9,192,537,116.71
Utility Profits:	$ 70,540,320.00	$ 67,468,583.70	$ 64,396,847.40	$ 552,123,347.40	$ 693,390,287.40	$ 673,985,251.10	$ 677,635,588.73	$ 689,440,283.75
Short-Term Nuclear								
Total Rate Base:				$ 1,400,000,000.00	$ 1,365,000,000.00	$ 1,330,000,000.00	$ 1,295,000,000.00	$ 1,260,000,000.00
Utility Profits:				$ 105,000,000.00	$ 102,375,000.00	$ 99,750,000.00	$ 97,125,000.00	$ 94,500,000.00
Long-Term Nuclear								
Total Rate Base:				$ 1,400,000,000.00	$ 1,365,000,000.00	$ 1,330,000,000.00	$ 1,295,000,000.00	$ 1,260,000,000.00
Utility Profits:				$ 105,000,000.00	$ 102,375,000.00	$ 99,750,000.00	$ 97,125,000.00	$ 94,500,000.00
ACE								
Total Rate Base:				$ 1,400,000,000.00	$ 1,365,000,000.00	$ 1,330,000,000.00	$ 2,173,200,000.00	$ 2,108,926,666.67
Utility Profits:				$ 105,000,000.00	$ 102,375,000.00	$ 99,750,000.00	$ 162,990,000.00	$ 158,169,500.00

Renewable	2025	2026	2027	2028	2029	2030	2031	2032
Total Rate Base:	$ 11,876,645,984.58	$ 14,540,689,297.90	$ 15,855,067,345.85	$ 17,356,001,479.40	$ 18,260,819,524.08	$ 18,911,414,914.90	$ 18,811,408,344.12	$ 18,363,344,151.77
Utility Profits:	$ 890,748,448.84	$ 1,090,551,697.34	$ 1,189,130,050.94	$ 1,301,700,110.96	$ 1,369,561,464.31	$ 1,418,356,118.62	$ 1,410,855,625.81	$ 1,377,250,811.38
Short-Term Nuclear								
Total Rate Base:	$ 1,225,000,000.00	$ 7,014,042,729.07	$ 6,829,472,290.13	$ 6,644,901,851.20	$ 12,281,947,529.60	$ 17,769,506,445.33	$ 17,285,962,481.07	$ 16,802,418,516.80
Utility Profits:	$ 91,875,000.00	$ 526,053,204.68	$ 512,210,421.76	$ 498,367,638.84	$ 921,146,064.72	$ 1,332,712,983.40	$ 1,296,447,186.08	$ 1,260,181,388.76
Long-Term Nuclear								
Total Rate Base:	$ 1,225,000,000.00	$ 1,190,000,000.00	$ 1,155,000,000.00	$ 1,120,000,000.00	$ 1,085,000,000.00	$ 5,826,212,893.87	$ 8,059,729,930.67	$ 7,845,345,815.47
Utility Profits:	$ 91,875,000.00	$ 89,250,000.00	$ 86,625,000.00	$ 84,000,000.00	$ 81,375,000.00	$ 436,965,967.04	$ 604,479,744.80	$ 588,400,936.16
ACE								
Total Rate Base:	$ 2,044,653,333.33	$ 2,834,380,000.00	$ 2,741,640,000.00	$ 2,648,900,000.00	$ 2,556,160,000.00	$ 2,463,420,000.00	$ 2,370,680,000.00	$ 2,277,940,000.00
Utility Profits:	$ 153,349,000.00	$ 212,578,500.00	$ 205,623,000.00	$ 198,667,500.00	$ 191,712,000.00	$ 184,756,500.00	$ 177,801,000.00	$ 170,845,500.00

Renewable	2033	2034	2035	2036	2037	2038	2039	2040
Total Rate Base:	$ 17,434,685,476.38	$ 16,506,026,800.99	$ 16,178,103,720.20	$ 16,063,527,594.87	$ 15,234,264,914.58	$ 14,233,363,492.97	$ 13,249,136,971.36	$ 12,264,910,449.75
Utility Profits:	$ 1,307,601,410.73	$ 1,237,952,010.07	$ 1,213,357,779.02	$ 1,204,764,569.62	$ 1,142,569,868.59	$ 1,067,502,261.97	$ 993,685,272.85	$ 919,868,283.73
Short-Term Nuclear								
Total Rate Base:	$ 16,318,874,552.53	$ 15,835,330,588.27	$ 15,351,786,624.00	$ 17,779,050,718.40	$ 17,220,763,372.80	$ 16,662,476,027.20	$ 16,104,188,681.60	$ 15,545,901,336.00
Utility Profits:	$ 1,223,915,591.44	$ 1,187,649,794.12	$ 1,151,383,996.80	$ 1,333,428,803.88	$ 1,291,557,252.96	$ 1,249,685,702.04	$ 1,207,814,151.12	$ 1,165,942,600.20
Long-Term Nuclear								
Total Rate Base:	$ 7,630,961,700.27	$ 7,416,577,585.07	$ 7,202,193,469.87	$ 6,987,809,354.67	$ 6,773,425,239.47	$ 11,932,280,629.87	$ 11,583,358,428.27	$ 11,234,436,226.67
Utility Profits:	$ 572,322,127.52	$ 556,243,318.88	$ 540,164,510.24	$ 524,085,701.60	$ 508,006,892.96	$ 894,921,047.24	$ 868,751,882.12	$ 842,582,717.00
ACE								
Total Rate Base:	$ 2,185,200,000.00	$ 2,092,460,000.00	$ 1,999,720,000.00	$ 1,906,980,000.00	$ 1,904,240,000.00	$ 1,868,300,000.00	$ 1,770,566,666.67	$ 1,672,833,333.33
Utility Profits:	$ 163,890,000.00	$ 156,934,500.00	$ 149,979,000.00	$ 143,023,500.00	$ 142,818,000.00	$ 140,122,500.00	$ 132,792,500.00	$ 125,462,500.00

Renewable	2041	2042	2043	2044	2045	2046	2047	2048
Total Rate Base:	$ 12,979,890,470.64	$ 12,150,019,882.61	$ 11,148,510,553.27	$ 10,463,317,544.35	$ 9,470,719,549.73	$ 10,597,802,168.10	$ 11,461,160,079.92	$ 11,960,311,029.75
Utility Profits:	$ 973,491,785.30	$ 911,251,491.20	$ 836,138,291.50	$ 784,748,815.83	$ 710,303,966.23	$ 794,835,162.61	$ 859,587,005.99	$ 897,023,327.23
Short-Term Nuclear								
Total Rate Base:	$ 14,987,613,990.40	$ 14,429,326,644.80	$ 16,200,020,451.20	$ 15,582,273,105.60	$ 14,964,525,760.00	$ 14,346,778,414.40	$ 13,729,031,068.80	$ 13,111,283,723.20
Utility Profits:	$ 1,124,071,049.28	$ 1,082,199,498.36	$ 1,215,001,533.84	$ 1,168,670,482.92	$ 1,122,339,432.00	$ 1,076,008,381.08	$ 1,029,677,330.16	$ 983,346,279.24
Long-Term Nuclear								
Total Rate Base:	$ 10,885,514,025.07	$ 10,536,591,823.47	$ 10,187,669,621.87	$ 9,838,747,420.27	$ 9,489,825,218.67	$ 9,140,903,017.07	$ 8,791,980,815.47	$ 8,443,058,613.87
Utility Profits:	$ 816,413,551.88	$ 790,244,386.76	$ 764,075,221.64	$ 737,906,056.52	$ 711,736,891.40	$ 685,567,726.28	$ 659,398,561.16	$ 633,229,396.04
ACE								
Total Rate Base:	$ 1,575,100,000.00	$ 1,477,366,666.67	$ 1,379,633,333.33	$ 1,281,900,000.00	$ 1,184,166,666.67	$ 1,086,433,333.33	$ 988,700,000.00	$ 890,966,666.67
Utility Profits:	$ 118,132,500.00	$ 110,802,500.00	$ 103,472,500.00	$ 96,142,500.00	$ 88,812,500.00	$ 81,482,500.00	$ 74,152,500.00	$ 66,822,500.00

Renewable	2049	2050
Total Rate Base:	$ 10,786,412,367.81	$ 10,905,083,272.68
Utility Profits:	$ 808,980,927.59	$ 817,881,245.45
Short-Term Nuclear		
Total Rate Base:	$ 12,493,536,377.60	$ 11,875,789,032.00
Utility Profits:	$ 937,015,228.32	$ 890,684,177.40
Long-Term Nuclear		
Total Rate Base:	$ 8,094,136,412.27	$ 19,088,719,833.60
Utility Profits:	$ 607,060,230.92	$ 1,431,653,987.52
ACE		
Total Rate Base:	$ 793,233,333.33	$ 789,500,000.00
Utility Profits:	$ 59,492,500.00	$ 59,212,500.00

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