INDUSTRIAL COMMISSION OF NORTH DAKOTA

NORTH DAKOTA TRANSMISSION AUTHORITY

Analysis of Finalized Rule for

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

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Always On Research

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Executive Summary

On behalf of the North Dakota Transmission Authority (NDTA), the Always On Energy Research prepared this study to analyze the potential impacts of EPA's finalized 111d/Greenhouse Gas Rule on North Dakota's power generation and power grid reliability.

Our primary finding, which is drawn substantially from the Rule's administrative record, finalized rule and regulatory impact analysis, is not technologically feasible for lignite-based power generation facilities, will foreseeably result in the retirement of lignite power generation units, and will negatively impact consumers of electricity in the Midcontinent Independent Systems Operator (MISO) and Southwest Power Pool (SPP) systems by reducing the reliability of the electric grid and increasing costs for ratepayers.

Our analysis builds upon grid reliability data and forecasts from the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), and it assesses what is likely to happen to grid reliability if the Greenhouse Gas Rule forces some or all of North Dakota's lignite power generation units to retire. We determined that the closure of lignite-fired powered power plants in the MISO & SPP footprints would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO & SPP systems even if these resources are replaced with wind, solar, battery storage, and natural gas plants. In reaching that determination, we have accepted EPA's estimates for capacity values of intermittent and thermal resources.

Moreover, building such replacement resources would come at a great cost to MISO and SPP ratepayers. Replacing the retired coal, natural gas, and nuclear units in EPA's modeled MISO grid with the new wind, solar, battery storage, and natural gas facilities would cost an additional $381.9 billion through 2055 compared to the current operating costs of the existing fleet.

In SPP, replacing the retired coal, natural gas, and nuclear units in EPA's modeled grid with the new wind, solar, battery storage, and natural gas facilities would cost an additional $65.6 billion compared to the costs of operating the existing generation fleet.

EPA did not conduct hourly reliability modeling on its modeled MISO or SPP grids. It instead performed "resource adequacy" analyses that overestimate the availability of the thermal fleet and the reliability of the wind and solar fleet. When EPA's modeled MISO and SPP grids are subjected to an hourly reliability stress test, using hourly electricity demand in each RTO and hourly wind and solar capacity factors, the result is severe capacity shortfalls in both RTOs that result in great costs to families and businesses in these regions.

Using the 2020 historical comparison year for hourly wind and solar capacity factors and hourly electricity demand, EPA's modeled MISO grid would experience up to an additional 377,300 megawatt hours (MWh) of unserved load during the model run stretching from 2028-2055. These blackouts would cost $3.77 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Using the 2021 historical comparison year for hourly wind and solar capacity factors and hourly electricity demand, EPA's modeled SPP grid would experience **8.3 million** megawatt hours (MWh) of unserved load during the model run stretching from 2028-2055. **These blackouts would cost $83 billion** based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Section A: North Dakota's Power Environment

North Dakota Transmission Authority (NDTA)

The North Dakota Transmission Authority (NDTA) was established in 2005 by the North Dakota Legislative Assembly at the behest of the North Dakota Industrial Commission. Its primary mandate is to facilitate the growth of transmission infrastructure in North Dakota. The Authority serves as a pivotal force in encouraging new investments in transmission by aiding in facilitation, financing, development, and acquisition of transmission assets necessary to support the expansion of both lignite and wind energy projects in the state.

Operating as a 'builder of last resort,' the NDTA intervenes when private enterprises are unable or unwilling to undertake transmission projects on their own. Its membership, as stipulated by statute, comprises the members of the North Dakota Industrial Commission, including Governor, Attorney General, and Agriculture Commissioner.

Statutory authority for the North Dakota Transmission Authority (NDTA) is enshrined in Chapter 17-05 of the North Dakota Century Code. Specifically, Section 17-05-05 N.D.C.C. outlines the powers vested in the Authority, which include:

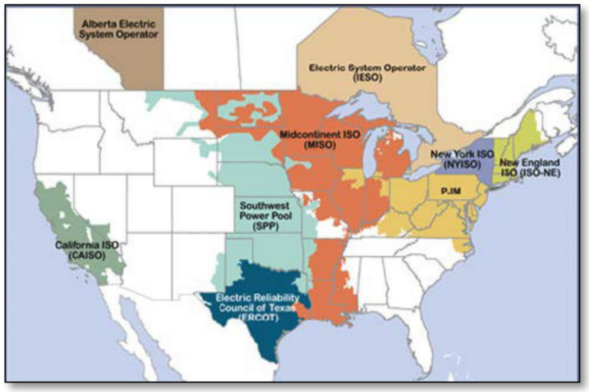
1. Granting or loaning money.
2. Issuing revenue bonds, with an upper limit of $800 million.
3. Entering into lease-sale contracts.
4. Owning, leasing, renting, and disposing of transmission facilities.
5. Entering contracts for the construction, maintenance, and operation of transmission facilities.
6. Conducting investigations, planning, prioritizing, and proposing transmission corridors.
7. Participating in regional transmission organizations.

In both project development and legislative initiatives, the North Dakota Transmission Authority (NDTA) plays an active role in enhancing the state's energy export capabilities and expanding transmission infrastructure to meet growing demand within North Dakota. Key to its success is a deep understanding of the technical and political complexities associated with energy transmission from generation sources to end-users. The Authority conducts outreach to existing transmission system owners, operators, and potential developers to grasp the intricacies of successful transmission infrastructure development. Additionally, collaboration with state and federal officials is essential to ensure that legislation and public policies support the efficient movement of electricity generated from North Dakota's abundant energy resources to local, regional, and national markets.

As the energy landscape evolves with a greater emphasis on intermittent generation resources, transmission planning becomes increasingly intricate. Changes in the generation mix and the redistribution of generation resource locations impose strains on existing transmission networks, potentially altering flow directions within the network. A significant aspect of the Authority's responsibilities involves closely monitoring regional transmission planning efforts. This includes observing the activities of regional transmission organizations (RTOs) recognized by the Federal Energy Regulatory Commission (FERC), which oversee the efficient and reliable operation of the transmission grid. While RTOs do not own transmission assets, they facilitate non-discriminatory access to the electric grid, manage congestion, ensure reliability, and oversee planning, expansion, and interregional coordination of electric transmission.

Many North Dakota service providers are participants in the Midcontinent Independent System Operator (MISO), covering the territories of several utilities and transmission developers. Additionally, some entities are part of the Southwest Power Pool (SPP), broadening the scope of transmission planning. Together, North Dakota utilities and transmission developers contribute to a complex system overseeing the transmission of over 200,000 megawatts of electricity across 100,000 miles of transmission lines, serving homes and businesses in multiple states.

MISO and SPP also operate power markets within their respective territories, managing pricing for electricity sales and purchases. This process determines which generating units supply electricity and provide ancillary services to maintain voltage and reliability. Overall, the NDTA's involvement in regional transmission planning and coordination is crucial for ensuring the reliability, efficiency, and affordability of electricity transmission across North Dakota and beyond.



FERC-Recognized Regional Transmission Organizations and Independent System Operators

(www.ferc.gov)

Generation Adequacy, Transmission Capacity & Load Forecast Studies

The North Dakota Transmission Authority (NDTA) conducts periodic independent evaluations to assess the adequacy of transmission infrastructure in the state. In 2023, the NDTA commissioned two generation resource adequacy studies, one for the Midcontinent Independent System Operator (MISO) and another for the Southwest Power Pool (SPP). Additionally, the NDTA recently completed a generation resource adequacy study examining the impact of the EPA's proposed Mercury and Air Toxics Standards (MATS) Rule. A transmission capacity study commissioned by the NDTA is scheduled for completion in the summer of 2024.

Regular load forecast studies are also commissioned by the NDTA, with the most recent study completed in 2021. This study, conducted by Barr Engineering, provided an update to the Power Forecast 2019, projecting energy demand growth over the next 20 years. The 2021 update incorporates factors such as industries expressing interest in locating in North Dakota, abundant natural gas availability from the Bakken wells, and the potential for carbon capture and sequestration from various sources. The 2021 update and the full study can be obtained from the North Dakota Industrial Commission website: Power Forecast Study – 2021 Update, https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-annualreport-21.pdf

The Power Forecast 2021 Update projects a 10,000 GWhr increase in energy demand over the next two decades under the consensus scenario, requiring approximately 2200 to 2500 MW of additional capacity to meet demand. These projections are closely tied to industrial development forecasts and are coordinated with forecasts used by the North Dakota Pipeline Authority. These projections were highly dependent on industrial development and are premised on new federal regulations not forcing the early retirement of even more electric generation units.

Meeting this growing demand poses significant challenges for utilities responsible for providing reliable service. While there is considerable interest in increasing wind and solar generation, natural gas generation is also essential to provide stability to weather-dependent renewable sources. Importantly, load growth across the United States is driven by the electrification of transportation, heating/cooling systems, data centers, and manufacturing initiatives.

Studies consistently highlight the critical importance of maintaining existing dispatchable generation to prevent grid reliability failures. Ensuring uninterrupted power supply is paramount for national security, public safety, food supply, and overall economic stability. The NDTA's ongoing assessments and proactive planning are crucial for meeting the evolving energy needs of North Dakota while maintaining grid reliability and resilience.

The timing and implementation of resources to meet this growing demand is a significant challenge for the utilities. Importantly, electric demand growth across the United States over the next several decades is projected to be dramatic due to the electrification of transportation, home heating/conditioning, data center and artificial intelligence centers, as well as the effort to bring manufacturing back to the USA. Studies by NDTA and others all point to the critical need to keep all existing dispatchable generation online to avoid catastrophic grid reliability failures and have been warning that the push to force the retirement of reliable, dispatchable fossil fuel generation units is occurring before it is projected there will be sufficient intermittent units in place to cover the anticipated increase in demand. And when demand for electricity exceeds the dispatchable supply, the foreseeable result will be blackouts or energy rationing.

Current North Dakota Generation Resources

Here is the current breakdown of North Dakota's generation resources:

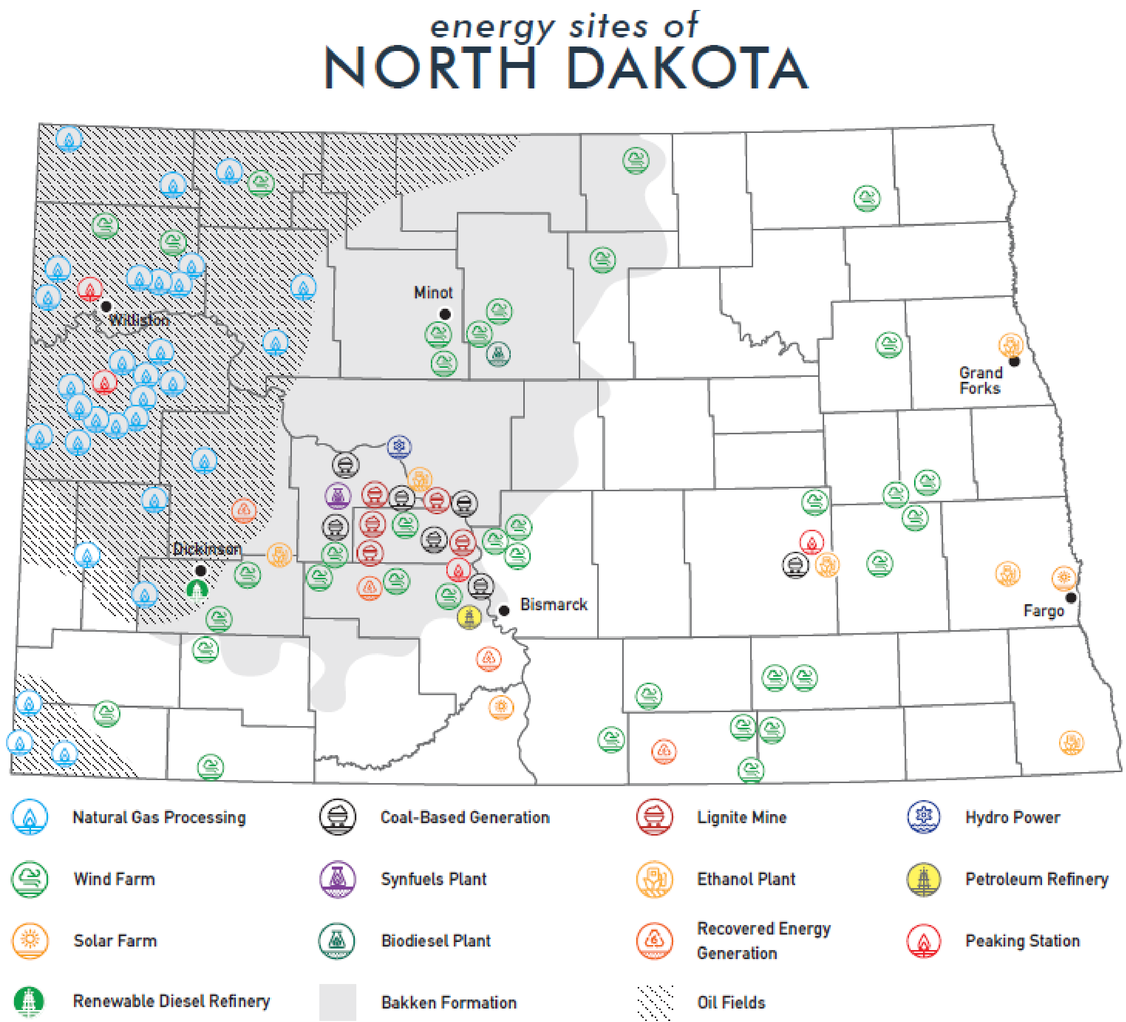
1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW since it is intermittent. This is representative of the amount that is estimated to be available for the peak demand in the summer.
    - Solar Generation: Although North Dakota currently lacks utility-scale solar generation facilities in operation, some projects are in the queues of regional transmission organizations like MISO and SPP, indicating potential future development in this area.
2. Thermal Coal Generation:
    - North Dakota currently operates thermal coal generation at six locations, comprising a total of 10 generating units with a combined capacity of approximately 4,048 MW.
    - The average capacity factor for these generating plants ranged from 65% to 91% in

2021, excluding the retired Heskett Station.

- Rainbow Energy operates the Coal Creek Station and the DC transmission line that transports ND produced energy to the Minneapolis region. Rainbow Energy is assessing a CO2 capture project for the facility. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity on the DC line.

3. Hydro Generation:
    - North Dakota has one hydro generation site equipped with 5 units, boasting a total capacity of 614 MW.
    - However, the average capacity factor declined to approximately 43% in 2021 due to limitations imposed by water flow in the river, particularly during drought years.
4. Natural Gas Generation:
    - North Dakota operates three sites for electric generation utilizing natural gas, comprising 21 generating units with a total capacity of 596.3 MW.
    - These units include reciprocating engines and gas turbines, with variation in summer capacity influenced by the performance of gas generators in hot weather.
    - Total natural gas generation in North Dakota remained steady from 2019 through 2021, amounting to 1.445 GWhr in 2021.
5. Total Generation:
    - The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW.
    - Wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW due to its intermittent nature, down from 4,250MW of installed capacity, representing the estimated amount available during peak summer demand. However, newer installations have demonstrated slightly higher capacity for accreditation.

This comprehensive overview underscores the diverse mix of generation resources in North Dakota, with significant contributions from wind, coal, hydro, and natural gas. Continued assessment and adaptation to evolving energy needs and market dynamics are essential for ensuring a reliable and sustainable energy future for the state.



+ *Map courtesy of Bismarck State College National Energy Center of Excellence.*

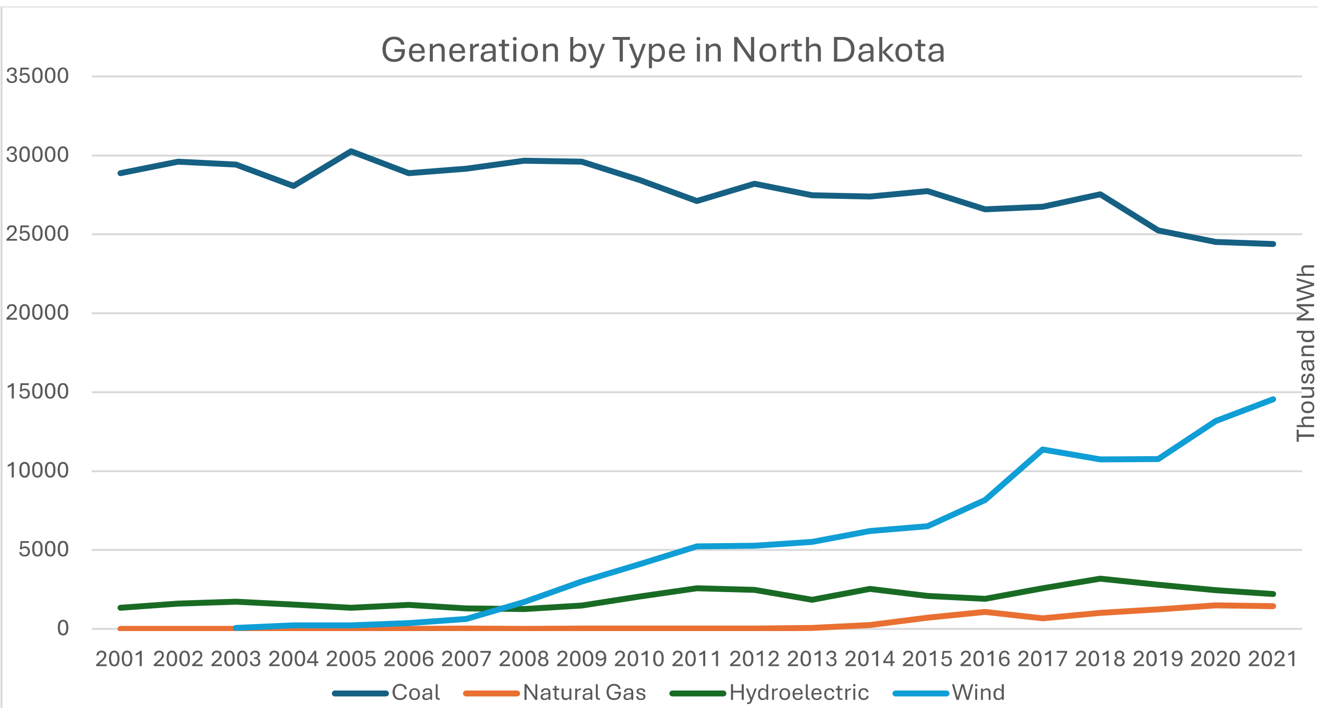
Electric Generation Market & Utilization

In recent decades, North Dakota has emerged as a significant exporter of electricity, primarily fueled by the development of thermal lignite generation in the western part of the state since the 1960s. Concurrently, transmission infrastructure has been expanded to facilitate the export of electricity to markets predominantly situated to the east. Moreover, North Dakota has garnered recognition as an excellent source of wind generation, leading to additional transmission development to accommodate the transmission of this renewable energy to markets.

According to data from the Energy Information Administration, in 2020, North Dakota generated a total of 42,705 MWh of electricity from all sources, with 48% of this total being exported beyond the state's borders over two large high voltage direct current lines (HVDC), which serve load in the neighboring state of Minnesota and multiple 345kv and 230kv alternating current (AC) transmission lines serving surrounding states. Wind generation accounted for 34% of North

Dakota's total electricity generation in 2023, highlighting the growing significance of renewable energy in the state's energy portfolio. Notably, industrial demand in North Dakota experienced substantial growth, expanding by nearly 30% in 2023.

While demand for electricity in markets outside of North Dakota, and in most areas within the state, has remained relatively stable in recent years, the Bakken region has witnessed notable demand growth. Over the past 16 years, total electricity generation in North Dakota has increased from 29,936 MWh to 42,705 MWh, with retail sales climbing from 10,516 MWh to 22,975 MWh. This growth is primarily attributed to the burgeoning development of the Bakken oil fields. Industrial consumption in North Dakota also witnessed a robust increase of over 11% in 2020, with power forecasts projecting a continued upward trajectory in demand.



Grid Resource Adequacy and Threats to Growth Opportunities

In 2023, both the MISO and SPP grid operators issued warnings about the adequacy of generation resources to meet peak demand situations. This highlights a growing concern that the desired pace of change towards a more sustainable energy future is outpacing the achievable pace of transformation. This concern is underscored by the stark increase in grid events necessitating the activation of emergency procedures. **For instance, prior to 2016, MISO had no instances requiring the use of emergency procedures, but since then, there have been 48 Maximum Generation events.**

Many experts in the industry project that, despite ambitious goals, realistic scenarios still foresee a substantial dependence on fossil fuel energy—potentially up to 50%—even by 2050. While efforts to decarbonize fossil fuel resources are underway, achieving complete carbon neutrality or a fully renewable energy grid by 2050 appears increasingly unlikely. The scalability and affordability of storage technology, particularly for renewable energy sources, remain significant challenges.

In response to these challenges, Governor Burgum has issued a visionary goal for North Dakota to achieve carbon neutrality in its combined energy and agriculture sectors by 2030. Governor Burgum's approach emphasizes innovation over mandates, aiming to attract industries and technologies that support this goal to the state. The initiative seeks to leverage advancements in carbon capture and sequestration technologies to retain conventional generation in North Dakota while also promoting sustainable agricultural practices and other innovative solutions, such as CO2 sequestration from ethanol production and enhanced oil recovery. These efforts demonstrate a commitment to proactive and pragmatic solutions to address the complexities of achieving carbon neutrality in the energy and agriculture sectors.

The state's vision for a decarbonized energy generation future faces significant challenges due to the individual and cumulative impact of expansive federal rulemakings. These regulations would curtail the flexibility to achieve the 2030 goal through the deployment of carbon capture and sequestration (CCS) technologies. Furthermore, they would impose financial burdens on electric cooperatives and utilities with limited resources, diverting investment away from future growth options toward retrofitting existing facilities with costly emissions technologies to comply with new federal requirements.

This regulatory burden not only impedes progress towards decarbonization but also introduces opportunity costs for utilities and cooperatives. The funds that would otherwise be allocated for future growth and innovation in clean energy solutions are instead diverted to compliance measures, hindering the state's ability to transition to a more sustainable energy future efficiently and effectively.

Ultimately, the restrictive nature of these federal rulemakings poses a significant obstacle to North Dakota's efforts to achieve its decarbonization goals and undermines the state's vision for a cleaner and more sustainable energy generation landscape. It highlights the need for a balanced approach to regulation that supports innovation and investment in carbon reduction technologies while also allowing for continued economic growth and development in the energy sector.

Grid Reliability Is Already Vulnerable

The fragility of grid reliability is already evident as warnings have been issued due to the declining ratio of dispatchable and intermittent generation supplies. This concerning trend poses significant threats to public safety, economic stability, and national security. Grid reliability is vital for ensuring continuous access to essential services, such as food production and military operations. Dispatchable reliable generation forms the backbone of grid stability, enabling the balancing of supply and demand fluctuations. Failure to address these reliability concerns will compromise critical infrastructure and expose society to substantial risks. Urgent action is required to safeguard grid reliability and mitigate the potential consequences for public safety and national security.

NERC's 2023 Reliability Risk Assessment

The North American Electric Reliability Council's 2023 Reliability Risk Assessment[1] are concerning as demonstrated in the slides below. The electrification of the US economy, data & AI center growth and the build it at home initiatives will substantially increase the demand for electricity generation and transmission.

NERC's 2023 Summer Reliability Assessment warns that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand. While there are no high-risk areas in this year's assessment, the number of areas identified as being at elevated risk has increased. The assessment finds that, while resources are adequate for normal summer peak demand, if summer temperatures spike, seven areas — the U.S. West, SPP and MISO, ERCOT, SERC Central, New England and Ontario — may face supply shortages during higher demand levels.

"Increased, rapid deployment of wind, solar and batteries have made a positive impact," said Mark Olson, NERC's manager of Reliability Assessments. "However, generator retirements continue to increase the risks associated with extreme summer temperatures, which factors into potential supply shortages in the western two-thirds of North America if summer temperatures spike."

The North American Electric Reliability Corporation (NERC) recently released its 2023 Long-Term Reliability Assessment (LTRA), which found MISO is the region most at risk of capacity shortfalls in the years spanning from 2024 to 2028 due to the retirement of thermal resources with inadequate reliable generation coming online to replace them.[2]

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[1] NERC. "North American Reliability Assessment." North American Electric Reliability Corporation, May 2023, https://www.nerc.com/news/Headlines%20DL/Summer%20Reliability%20Assessment%20Announcement%20May%202023.pdf.

[2] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

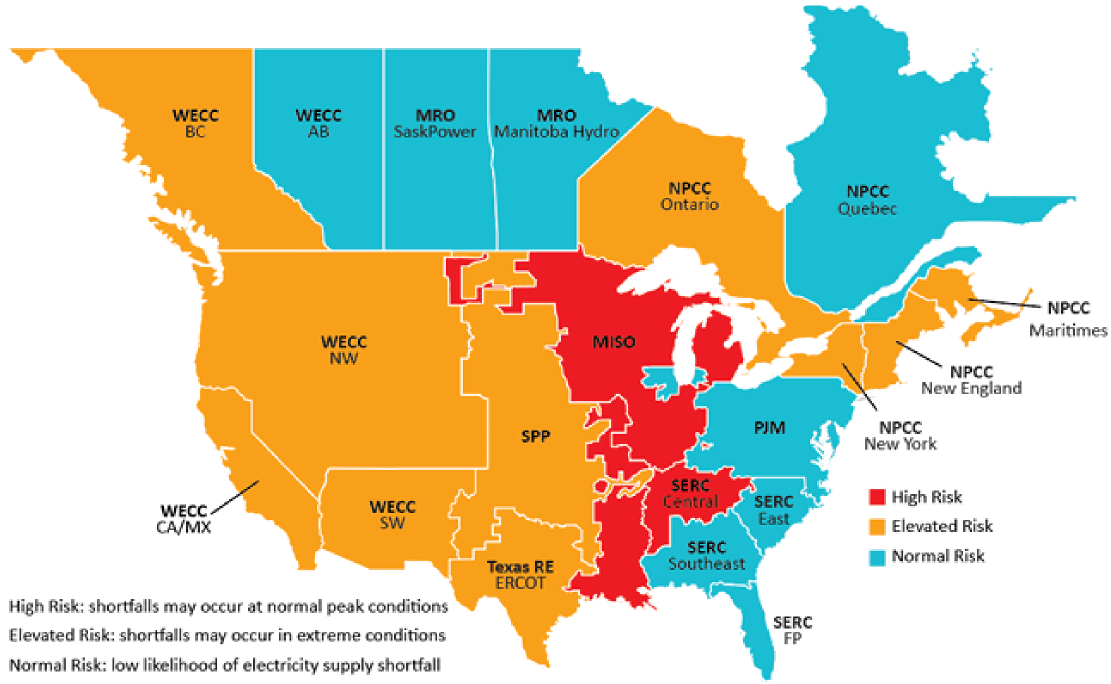

Figure 1: Risk Area Summary 2024–2028[8]

MISO is the region most at risk of rolling blackouts in the near future.

In 2028, MISO is projected to have a 4.7 GW capacity shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW, leaving MISO at risk of load shedding during normal peak conditions. This is because the new wind and solar resources that are being built have significantly lower accreditation values than the older coal, natural gas, and nuclear resources that are retiring.[3]

MISO's Public Comments on Greenhouse Gas Rule

Found in the public comments from MISO, submitted on August 8, 2023, was a warning and grave concern about increasing challenges to grid reliability and the ability to commit sufficient resources to supply electricity to customers.[4]

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[3] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[4] Studies conducted by MISO and other Regional Transmission Organizations (RTOs) have verified that their transmission systems are at their capacity and there are financial and other impairments currently impacting the ability to address this lack of capacity issue. MISO's Long Range Transmission Plan details interconnection issues3 and its Planning Resource Auction (PRA) process shows strains in the availability of sufficient generating capacity to meet the region's needs. *See* MISO's 2022/2023 PRA resulted in a capacity shortfall for the MISO North/Central Regions despite the fact that MISO was able to import over 3,000 MW from neighboring regions. *See, e.g.*, MISO

"Even with the recognized growth of alternative and renewable energy sources, MISO continues to be concerned about ***the risk of a looming shortfall of resources and attributes needed to ensure grid reliability in the region****. Within the MISO region, MISO has seen an increasing trend of retirements of generation that will be needed to provide critical grid services into the near future.* ***These retirements are occurring far faster than new energy sources with equivalent attributes, whatever the fuel source, can be developed, constructed, and brought online.*** *While MISO is both fuel- and technology-neutral, it needs to preserve the best options to provide these needed resource capabilities and attributes to bridge the gap between retirements and replacement capabilities and attributes.*

MISO also is concerned about impacts from the Proposed Rule on grid reliability and resource adequacy[5] as MISO is experiencing a trending decline in reserve margin and fewer dispatchable "baseload" resources" *(i.e., currently in the form of coal and natural gas). Distinct types of resources are accredited, or count, for different amounts of capacity depending on how reliable they are to be able to generate at the time they are needed. Traditional dispatchable generators like coal and natural gas, tend to have much higher accredited capacity than the replacement capacity that has been brought online in recent years. Replacement of retiring generation with new, mostly intermittent facilities (i.e., solar and wind) that are not installed at the same time or valued at the same output presents its own risks. Moreover, new capacity from these resources is not always available to provide energy during times of need."*

2022/2023 Planning Resource Auction (PRA) Results, April 14, 2022, *available at* https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf. *See also* MISO 2022/2023 Planning Resource Auction (PRA) Results, Revised May 3, 2022, *available at* https://cdn.misoenergy.org/20220420%20RASC%20Item%2004b%20PRA%20Results%20Supplemental624128.pdf. *See* MISO 2022 Regional Resource Assessment (Nov. 2022), *available at* https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf (noting an overall decline in accredited capacity in 2022 and near term capacity risk as well as increased complexity of reliability operating and planning the electric system due to changes in generator sources); MISO's Response to the Reliability Imperative (Jan. 2023), *available at* https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf (addressing the shared responsibility of shareholders to address the urgent and complex challenges to electric system reliability and noting that the MISO region has been inching ever closer to experiencing a shortfall in electricity-generating capacity due to widespread retirements of conventional resources, not enough replacement capacity coming online, and other factors). FERC also notes backlogs of more than three years in the interconnection queue. *See* FERC Proposes Interconnection Reforms to Address Queue Backlogs, *available at*, https://www.ferc.gov/news-events/news/ferc-proposes-interconnection-reforms-address-queue-backlogs (noting significant current backlogs in the interconnection queues of more than three years).

[5] Resource adequacy, in general terms, is achieved when the accredited megawatt capacity of the generators in a particular region meets or exceeds the forecasted load, plus reserves, for that region.

MISO's Response to the Reliability Imperative (2024)

On February 26, 2024, the Midcontinent Independent System Operator (MISO) released "MISO's Response to the Reliability Imperative[6]," a report which is updated periodically to reflect changing conditions in the 15-state MISO region that extends through the middle of the U.S. and into Canada. MISO's new report explains the disturbing outlook for electric reliability in its footprint unless urgent action is taken. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliability attributes.

From 2014 to 2024, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve margin requirements.[7]

According to the Reliability Imperative, MISO uses an annual planning tool called the OMS-MISO Survey to compile information about new resources utilities and states plan to build and older assets they intend to retire. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time.

MISO lists U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would as a compounding reason for growing challenges to grid reliability. From the report, there is a section titled, "EPA Regulations Could Accelerate Retirements of Dispatchable Resources," which states:

> *"While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability.* ***In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.***
>
> *In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.*

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[6] MISO. "MISO'S Response to the Reliability Imperative Updated February 2024." MISO, February 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[7] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

> *MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline.* ***If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*** *The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources*."

In light of these shortcomings, the NDTA contracted with Always On Energy Research to model the impacts of the Greenhouse Gas rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

Conclusion: The Long-Term Reliability of the MISO Grid is Already Precarious

As the state agency responsible for the strategic buildout and framework of electricity distribution, the North Dakota Transmission Authority (NDTA) is deeply concerned about the potential impact of federal rulemakings on the generation fleet in North Dakota and the ability to support future growth initiatives. The current strain on the electric transmission system due to load growth is already posing significant challenges to grid reliability, particularly in areas facing transmission constraints and limited access to dispatchable generation.

The escalating frequency of grid events requiring emergency procedures, such as the 48 Maximum Generation events in MISO since 2016 and the increasing number of alerts issued by SPP, over 194 alerts issued in 2022, underscores the urgency of addressing transmission congestion and bolstering reliable generation capacity. The economic growth and security of North Dakota are directly tied to the timely development of new transmission facilities in tandem with dependable dispatchable electric generation. The impacts of grid strain extend beyond the energy sector, affecting multiple industries, ratepayers, and overall economic stability. Volatile wholesale prices and transmission congestion undermine business operations and investment confidence, hindering economic growth and prosperity. Moreover, reliable electricity supply is critical for essential services, including Department of Defense facilities, underscoring the broader implications of grid reliability issues.

Achieving a balanced generation portfolio requires careful consideration of reliability and resilience under all weather conditions, especially amidst the electrification of America and the imperative to safeguard public welfare and security.

Additionally, over 30% of the electricity generated in North Dakota is exported to neighboring states, magnifying the ripple effects of any regulations impacting dispatchable electricity generation resources. By responsibly managing the generation portfolio and prioritizing generation adequacy, North Dakota and the nation can seize significant opportunities for economic growth, innovation, and sustainable development.

Section B: North Dakota's Carbon Capture Advancements vs. Impending Challenges from the Greenhouse Gas Rule for Lignite Electric Generating Units

As a major energy producing state (from significant lignite coal, oil, natural gas, hydro and wind resources), North Dakota has an unmistakable sovereign interest in regulating the responsible development of its natural resources and their use. In fact, the North Dakota Legislature ("Legislature") has long declared it to be an essential government function and public purpose to foster and encourage the wise use and development of North Dakota's vast lignite coal resources to maintain and enhance the economic and general welfare of North Dakota.[8]

EPA's Finalized Rule would require North Dakota to submit a plan to EPA to reduce its carbon dioxide ("CO2") emissions, making retirement of its fleet of lignite fueled power plants "federally enforceable" unless the plants elect to commit to certain conditions. Those conditions would result in a dramatic and immediate shift away from lignite coal-powered electric generating plants in favor of gas-powered plants or renewable sources.

Indeed, according to EPA's own modeling, the Finalized Rule will lead to the closure of specific lignite coal-fueled electric generating plants. These closures would disproportionately harm North Dakota, as North Dakota has the largest known deposits of lignite coal in the world[9] and most of the coal mines in the State are lignite mines. The Finalized Rule would therefore not only deny North Dakota its sovereign authority to administer energy and environmental policies within its borders but would also deprive North Dakota of a substantial amount of tax and coal royalty payments, which can never be recovered.

The Finalized Rule would dictate North Dakota's energy policy, contrary to North Dakota's. extensive and longstanding statutory support for lignite coal-fueled electricity. EPA's Finalized Rule would usurp the authority and discretion of North Dakota and its respective agencies responsible for implementing environmental and energy policy.

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[8] North Dakota Century Code ("N.D.C.C.") § 54-17.5-01.

[9] North Dakota State Profile and Energy Estimates, Energy Information Administration (available at: https://www.eia.gov/state/?sid=ND#tabs-1 (last visited August 8, 2023))

The Finalized Rule would also have profound adverse impacts on North Dakota and the upper Midwest region's electric power sector and, in effect, redefine how electricity is generated and delivered through the electric power grids in these areas.

The Finalized Rule is an affront to North Dakota's sovereign interests in the continued use of its lignite coal resources to generate electricity and the state's past and ongoing significant investment in the development and implementation of technologies aimed at successfully capturing and geologically storing carbon emissions in North Dakota.

Numerous public comments in the administrative record, including from the regulated facilities in North Dakota and the North Dakota Department of Environmental Quality, provided EPA with notice that the proposed Greenhouse Gas regulatory standards are not technologically feasible, will impose crippling compliance costs that may require facility retirement, and will result in a significant portion of the dispatchable power provided by coal-generation facilities being taken off the grid. EPA chose not to redress those concerns with the Finalized Rule.

This report will summarize some of those concerns in the section that follows, however, a full study of the technological feasibility of complying with the new emissions standards is beyond the scope of this report. For the purposes of this report, we assume the regulated facilities and state regulator were forthright in their concerns about the feasibility of lignite-based facilities meeting the new standards.

Carbon Capture Project Status in North Dakota

North Dakota has been a leader in CCS technology development for North Dakota lignite-fueled power plants, and North Dakota is well positioned to be the first state with a full-scale EGU CCS facility. As such, North Dakota remains cautiously optimistic that CCS technology can be implemented at a large scale, considering the significant efforts put forth in research, development, and testing of this state-of-the-art technology. However, state officials and industry in North Dakota are greatly concerned about the unrealistic threshold for percentage of carbon captured on regulated facilities and the short compliance timeline for carbon capture retrofits to be permitted, financed, constructed and operational to scale by 2032.

Carbon Capture Technology Has Great Potential But Has Not Been Adequately Demonstrated

For nearly 20 years, North Dakota has actively supported the demonstration and development of CCS in North Dakota due to its superior carbon removal potential and associated large-scale job creation. While North Dakota's ongoing and significant efforts to advance CCS show tremendous promise, North Dakota does not believe that the technology currently meets the statutory requirement of CAA Section 111 (a) for technology that "has been adequately demonstrated" to require its wide-spread application on the Finalized Rule's accelerated time frames.

North Dakota has actively supported obtaining such an outcome and believes it is well situated to obtain that reality in the future. However, CCS is not yet a proven technology that can be deployed at a national scale, certainly not at the unachievable capture rates contemplated by EPA' s Finalized Rule. Under the Finalized Rule, EPA seeks to require CCS with 90% removal to be installed on units not included in other subcategories by January 1, 2032, with a retirement horizon of 2039 or later. EGUs without federally enforceable retirement dates that do not opt in to one of EPA's three other retirement subcategories are assigned to the post-2040 subcategory with its 90% CCS retrofit requirement by January 1, 2032.

North Dakota objects to this requirement because these EGUs likely differ widely in age, size, capacity factor, access to suitable CO2 storage, technical and economic feasibility of retrofitting CCS, and because real world experience shows that even though EGUs can be designed to capture 90% or more of CO2, the actual rates are lower due to operational difficulties and availability of the capture unit. These realities are closely documented by the University of North Dakota's Energy and Environmental Research Center ("EERC").[10]

None of the examples of successful plant operation that serve as EPA' s basis for claiming adequate demonstration meet the proposed standards for the CCS pathway. EPA' s examples "do not reflect the needs as set forth by EPA as they are examples of slipstream systems, are smaller capacity units, do not employ the full CCS process, and are capturing CO2 at levels below 90%."[11] There are currently only two large-scale coal units with CCS - Boundary Dam Unit 3 and Petra Nova. Of these two, only Boundary Dam is in operation, and it is operating at levels below compliance with the Finalized Rule.[12]

The lack of infrastructure and storage currently available, and the long timeframes to develop storage locations, contradict EPA's assumption that affected EGUs will have viable options to take captured CO2 away from the plant site to be properly geologically sequestered. EPA' s proposed compliance timeline is unrealistic. EPA erroneously presents a purportedly "reasonable" timeline

[10] *See* EERC, *Examination of EPA 's Proposed Emission Guidelines Under 40 CFR PART 60, Final Report 2023-EERC-08-04,* Aug. 2023 ("EERC Report"), at 5-6, **Ex. 1.**
[11] 42 U.S.C. § 7411 (b)(2).

[12] Public Comments from C. Beth (Hardy) Valiaho, VP - Policy, Regulatory & Stakeholder Relations of the International CCS Knowledge Centre, addressed to the Honorable Michael Regan, Administrator of the U.S. Environmental Protection Agency. Aug. 2023

of seven years to deploy CCS and related infrastructure and equipment. As demonstrated by the EERC, a more realistic timeframe CCS deployment is at least 10 years.[13]
The technology, materials, infrastructure, and regulatory processes required to replace the current dispatchable thermal generation and power capacity within EPA's proposed timeframe cannot be met.

In the Joint Public Comments of the Electric Reliability Council of Texas, Inc., Midcontinent Independent System Operator, Inc., PJM Interconnection, LLC, and Southwest Power Pool, Inc., they collectively share the concern of the overstatement of commercial viability of new technologies that the Proposed Rule's assumption that new technologies like carbon capture and storage (CCS) and hydrogen co-firing will be economically feasible within the specified timeframes is overstated and proceeding with these requirements could jeopardize the reliability of the electric grid[14]:

> "Although the Joint ISOs/RTOs have been and will continue to be supportive of new technologies, we believe that the Proposed Rule's Best System of Emissions Reduction (BSER) determination overstates the commercial viability of CCS and hydrogen co-firing today and ignores the cost and practicalities of developing new supporting infrastructure within the time frames projected. Without firm proof of the commercial and operational viability of these technologies, proceeding with these requirements could place the reliability of the electric grid in jeopardy. In short, hope is not an acceptable strategy."

Unachievable Rule Compliance Deadline of 2032

EPA assumes that electric utilities will begin work on the development of CCS projects upon issuance of a final rule on May 9, 2024, which is prior to each individual state's development and submission to EPA of their state implementation plans by June 2026 and EPA's approval of those state implementation plans by August 2027. Even if electric utilities could expend major financial resources, carbon capture projects currently cost over $1.5 billion depending on the size and scope of the power plant, for CCS project development at an early date of May 2024 this would still leave only 7.5 years for the development of a CCS project and begin to comply with the CO2 performance standard based on 90 percent removal by January 1, 2032. This compressed timeframe simply does not provide enough time for electric utilities to complete all the steps necessary to develop a CCS project from concept through the deployment of onsite capture

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[13] EERC, *Timeline for Implementation of Full-Scale Carbon Capture* (July 2023), at 7, **Ex. 2;** Plains CO2 Reduction ("PCOR") Partnership Timeline, Aug. 2023, **Ex. 3.**
[14] Joint Comments of Electric Reliability Council of Texas, Inc.; Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C. ; and Southwest Power Pool, Inc. on the Proposed Rule for Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units. August 8, 2023.

technology, as well as building out the pipeline transportation infrastructure and securing the permits necessary for the injection of the CO2 emissions for sequestration or EOR purposes.[15]

Despite opposition, the EPA asserts that its condensed 7.5-year timeline is "reasonable" due to potential efficiencies in project scheduling and concurrent execution of various development steps. However, the EPA's justification for this compressed schedule remains insufficient, as discussed earlier. Furthermore, the Agency's proposed timeframe of 7.5 years diverges from other estimates regarding the completion duration for all necessary steps in launching a CCS project from inception to operation.

One notable example is that the Global CCS Institute (an organization whose mission is to promote CCS development) projects almost nine years to complete a CCS project and also has gone the record of saying that "a large complex CCS project may take a decade to progress from concept to operation."[16] Similarly, EPA's 7.5 year estimate is much shorter than the time schedules estimated for actual CCS projects (both planned and actually completed) that can take ten or more years to complete.[17]

This conclusion was notably drawn from an analysis of the time frames observed in specific CCS projects that have either been completed or are currently in the initial stages of development.[18] The time schedules from these projects unmistakably affirm that a 7.5-year timeline is unrealistic, with typically ten years or more being necessary for their development.[19] The extended timeframe is imperative to fulfill crucial components of the project, encompassing:

- Design, engineering, planning, permitting, fabrication, and installation of the CCS technology for capturing the CO2 emissions from the coal-fired EGU;
- Development, siting, permitting, and construction of the pipeline for transporting the CO2 captured by the CCS equipment;
- Obtaining UIC Class VI permits and pore space for the injection and long-term storage of the captured CO2 in an underground geologic formation; and
- Development and construction of multiple CO2 injection wells and associated infrastructure.

Additionally, achieving the completion of CCS projects and meeting the applicable CO2 performance standards within an extended timeframe may prove unattainable for certain projects. This is often due to permitting challenges and other technical obstacles that surpass the control of

[15] America's Power Comments on the Proposed Carbon Rule for Fossil Fuel Plants. August 8, 2023.
[16] Global CCS Institute, *Global Status of CCS 2022* at 47-48.
[17] *See* Technical Comments on Carbon Capture Utilization and Sequestration Prepared for and Submitted by America's Power to EPA Docket, at 15 -16 (CCS Technical Report).
[18] CCS Technical Report at 30-35.
[19] CCS Technical Report at ii, 30-35.

CCS technology proponents. One prominent hurdle is the potential for protracted delays stemming from legal disputes over permits and other authorizations vital for constructing and operating carbon capture, transport, and storage facilities integral to CCS projects. Furthermore, significant delays can arise from federal and state permitting authorities' inability to issue permits promptly, often due to resource constraints and a backlog of project applications. This bottleneck is particularly evident in the case of UIC Class VI permits, where an existing backlog is expected to worsen with the heightened demand for permitting CCS projects under the Finalized Rule. The elongated timeframes required for CCS project development underscore the impracticality of the EPA's compressed schedule.

Permitting Timeline Challenges

North Dakota is uniquely positioned to lead in the development and implementation of carbon capture facilities on coal and gas generation facilities due to its state primacy. Nevertheless, the EPA's finalized rule overlooks the permitting timeline obstacles faced by projects in states lacking such authority, rendering the fulfillment of the federal implementation mandate by 2032 unattainable.

Currently, there are only three states (North Dakota, Wyoming and Louisiana) that have been delegated primacy to regulate and permit Class VI well programs, which are the type of permitted wells needed to sequester carbon dioxide underground.[20] According to EPA, 130 Class VI permits are currently pending review by the agency. Additional permits are under review by three states with delegated authority for state Class VI UIC programs.

In North Dakota, the delegated primacy was granted to the NDIC which consists of the Governor, the Attorney General, and the Commissioner of Agriculture, and regulates several North Dakota industries. Under N.D.C.C.§ 38-22-03, the Legislature delegated specific authority to the NDIC to regulate activities related to carbon capture technology.

Through its financing authority and oversight of numerous grant programs, the NDIC has invested millions of dollars in the past 15 years into the research and development of carbon capture technologies and geologic exploration to survey underground storage locations in deep saline formations in North Dakota. The NDIC approves grants and loans through its Lignite Research Program and its Clean Sustainable Energy Authority to carry out the legislative purposes of N.D.C.C. Ch. 38-22.

One of the NDIC's divisions, the Department of Mineral Resources' Oil and Gas Division carries out the regulatory responsibilities for the programs and permitting associated with geologic

[20] Congressional Research Service, "Class VI Carbon Sequestration Wells: Permitting and State Program Primacy," April 16, 2024.

sequestration. Under N.D.C.C. § 38-22-08, there are 14 requirements that must be met before the NDIC can issue a permit, and the N.D. Admin. Code provides additional requirements and procedures for the NDIC to issue a permit. Under N.D.C.C. § 38-22-17, the NDIC has the power to issue a certificate of project completion.

In 2013, the NDIC amended N.D. Admin. Code 43-05-01 to meet the "as stringent as" standard by incorporating EPA' s Class VI UIC program regulations under the federal Safe Drinking Water Act.[21] Thereafter, on June 21, 2013, North Dakota filed an application with the EPA to be the primary enforcement authority for UIC program. This would allow North Dakota to be granted the ability to permit projects for carbon capture sequestration instead of having long permitting times waiting for EPA approval.

In 2015, the Legislature authorized a Legislative Management Study to review the potential benefits and costs to industry, State, and environment for using carbon capture enhanced recovery methods.

The NDIC's Lignite Research Program provides grants and funding for near term, practical research and development projects that provide the opportunity to preserve and enhance development of our State's abundant lignite resources, which includes CCS. Lignite Research Program is funded from several sources including the coal severance tax, coal conversion tax, and oil and gas tax revenues with approximately $7.5 million available each year.

In 2017, the NDIC approved Lignite Research Program's creation of the Advanced Energy Technology Fund to further accelerate the deployment of CCS and other emerging technologies in North Dakota. The Legislature also passed a concurrent resolution requesting the United States Congress and the President to enact legislation expanding federal tax credits to cover carbon capture, utilization, and storage, and providing other incentives for carbon capture focused policies.

In 2018, nearly five years after North Dakota applied, the EPA approved North Dakota's request to implement and enforce its own Class VI UIC program. Class VI injection wells have extensive site characterization and comprehensive monitoring requirements. This approval made North Dakota the first state to obtain Safe Drinking Water Act primacy for Class VI UIC wells, which is necessary for the long-term storage of carbon dioxide captured from industrial and energy related sources. NDIC's Oil and Gas Division regulates Class VI injection wells.

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[21] EPA-HQ-OAR-2023-0072-0237, EPA, "INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS," Memo to the Docket, July 7, 2023, https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf

Also in 2018, the NDIC's Lignite Research Program approved a $15 million grant to Minnkota to fund a preliminary study regarding a significant CCS project at Minnkota. It also approved another $5 million grant to Minnkota in 2020 to allow for the evaluation of additional geologic storage of CO2 in underground formations adjacent to Minnkota' s plant. This State investment led to another $9.8 million grant from the DOE in 2019.

In 2021, after a 5-year investigative period, the NDIC approved the first-Class VI injection permit for an operational commercial-scale CCS project in North Dakota, Red Trail Energy. This approval process was completed in partnership with the DOE and the EERC. In 2022, the NDIC approved its second-Class VI storage facility permit for Minnkota's Project Tundra.

North Dakota's journey with carbon capture technology spans over 15 years, a testament to the collaborative efforts of state agencies and industry stakeholders. Despite this progress, the road ahead involves further investment of time and resources. Coal power plants face challenges in completing the financing and construction phases, indicating that additional time will be necessary to realize comprehensive implementation. Thus, while North Dakota's strides in carbon capture are commendable, sustained commitment and patience remain essential for the full realization of these initiatives.

Sovereignty Implications: The Finalized Greenhouse Gas Rule and North Dakota's Intrastate Energy Authority and Jeopardizes Grid Reliability

The regulation of electricity generation, transmission, and distribution has historically been the authority of individual states and state regulators, with few exceptions, wholesale rates, and targeted interference with interstate markets.[22] Despite the modem development of energy markets, grid, and utility services, retail sales of electricity and the development of regulated utility resources continue to be within the jurisdictional sphere of the States. This is especially pronounced in States like North Dakota.

North Dakota's authority over the intrastate generation and consumption of electricity is "one of the most important functions traditionally associated with the police powers of the States."[23] Despite the modem development of energy markets, grid, and utility services, retail sales of electricity and the development of regulated utility resources continue to be within the jurisdictional sphere of the States. Congress recognized State authority over these "important functions" in the Federal Power Act ("FPA"), which confines federal authority over electricity markets to "the transmission of electric energy in interstate commerce and the sale of such energy

[22] *FERC v. Elec. Power Supply Ass'n,* 577 U.S. 260,266 (2016), *as revised* (Jan. 28, 2016).
[23] *Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n,* 461 U.S. 375,377 (1983).

at wholesale in interstate commerce."[24] The FPA and other federal energy statutes respect the States' "traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related state concerns."[25]

The North Dakota Public Service Commission ("ND PSC") is a state agency created by the North Dakota Constitution to regulate and oversee intrastate energy production and consumption.[26] ND PSC has jurisdiction over economic regulation of public utilities and the orderly development and siting of energy infrastructure within the State. It is charged with determining whether to authorize generation, transmission, and other capital-intensive infrastructure in North Dakota that is needed by jurisdictional utilities, and has the authority to determine the generation mix, planning reserve margin, and enforce reliable service obligations of jurisdictional utilities.[27] ND PSC is a member and actively participates in the Organization of Midcontinent Independent System Operator ("MISO") and the Regional State Committee for Southwest Power Pool ("SPP"). Both MISO and SPP are engaged in transmission planning processes to accommodate the growth of renewable generation and the need to move that generation to the markets.[28]

The ND PSC has a statutory duty to ensure that North Dakotans receive a reliable supply of electricity and natural gas at just and reasonable rates. For the reasons stated below, the Finalized Rule infringes on the ND PSC's ability to fulfill its constitutional responsibilities and violates the rights historically and statutorily reserved for the States under the FPA.

The North Dakota Transmission Authority ("NDTA") was created by the Legislature with authority to make grants or loans; provide financing for approved transmission projects through bonds; own, lease, rent and dispose of transmission facilities; enter into contracts to construct, maintain and operate transmission facilities; engage in the relevant investigation and planning processes for transmission corridors; and participate in regional transmission organizations.[29] The purpose of the NDTA is to diversify and expand the North Dakota economy by facilitating development of transmission facilities to support the production, transportation, and utilization of North Dakota electric energy.[30]

The Finalized Rule inhibits NDTA from carrying out their sovereign purpose by increasing the risk potential for insufficient operating reserves, affecting NDTA's statutory right to facilitate

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[24] 16 U.S.C. § 824(a); *see also id.* § 824(b)(I).
[25] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm 'n,* 461 U.S. 190,205 (1983); *cf* 16 U.S.C. § 808(d)(2)(A).
[26] *See,* N.D. Const. art. 5, § 2.
[27] N.D.C.C. § 49-02 *et seq.*
[28] Isaac Orr et al., *Forecasting Resource Adequacy in Southwest Power Pool Through 2035* (May 15, 2023)
[29] N.D.C.C. § 17-05-05.
[30] *Id.*

effective transmission of North Dakota electric energy.[31] The preamble to the Finalized Rule acknowledges the critical need for reliability, but EPA fails to analyze and address reliability in the Finalized Rule. Rather, EPA relies on "design elements," its intention to exercise its enforcement discretion, and a resource adequacy analysis.

In the Finalized Rule's Preamble, EPA conflates resource adequacy with reliability. The Resource Adequacy Technical Support Document ("RA TSD") does not analyze reliability. The RA TSD "is meant to serve as a **resource adequacy** assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the [Inflation Reduction Act]."[32] EPA points to third party studies that purportedly demonstrate "how reliability continues to be maintained under high variable renewable penetration scenarios."[33] Even assuming these studies are correct (which North Dakota disputes), the ability to maintain reliability with an influx of new intermittent, weather-dependent renewable resources does not address the reliability impacts of potential retirement of significant volumes of existing baseload fossil-fuel fired generation or operation of new generating resources at lower capacity factors.[34]

Further threatening electric reliability in North Dakota is the potential future retirement of some EGUs as a result of the implementation of the Finalized Rule, contemplates with the projection that total coal retirements between 2023 and 2035 will be 126 GW (or 18 GW annually), as compared to an average historical retirement rate of 11 GW per year from 2015- 2020.[35] The retirements of dispatchable resources that can immediately increase or decrease power generation as needed results in significant uncertainty in the power grid, impacting the electric cooperatives' ability to reliably provide power and increasing the odds of unplanned outages.[36]

Reliability is even more crucial when considering that NDT A's power forecast for 2021 indicates an increase in energy demand of 10,000 GW over the next 20 years.[37]

Coal and natural gas EGUs are necessary to ensure reliability during times when intermittent generation is both available and unavailable. Transitioning reserve power generation sources to

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[31] Claire Vigesaa, Presentation: North Dakota Transmission Authority, regarding studies on the impact of the Environmental Protection Agency's (EPA's) regulations on the resource adequacy of the Midcontinent Independent System Operator and Southwest Power Pool grids (Aug. 7, 2023), Ex. 7.
[32] EPA, *Resource Adequacy Analysis Technical Support Document* (May 23, 2023). Available at: https://www.epa.gov/system/fi1es/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf
[33] EPA-HQ-OAR-2023-0034 at 2.
[34] Orr, Forecasting Resource Adequacy in Southwest Power Pool Through 2035.
[35] North Dakota currently has approximately 3,895 MW of coal-fired generation. U.S. Energy Information Administration, Energy Atlas (July 10, 2020), https://atlas.eia.gov/datasets/eia::power-plants/explore.
[36] NDIC, *North Dakota Transmission Authority presents electric grid resilience report* (July 29, 2022, 11 :00 PM),https:/ /www. ndic.nd. gov /news/north-dakota-transmission-authority-presents-electric-grid-resilience-report
[37] NDT A, Annual Report (July 1, 2021 to June 30, 2022),

intermittent sources increases the risk of outages as the nature of the energy source is not consistent like coal.[38] Accordingly, the Proposed Rule not only fails to provide an analysis of reliability impacts, but also threatens the grid's reliability.

Regional transmission organizations like MISO and SPP mandate load-serving entities to maintain sufficient generation capacity.[39] EPA's carbon standards could have major adverse impacts on the region's coal fleet, with 25 GW subject to CCS or gas co-firing requirements.[40] The loss of generation capacity would be made up through the construction of smaller natural gas combustion turbines using existing sites and interconnections.[41] This would exacerbate occurrences of observed natural gas scarcity and price increases.[42]

Given that predicted impacts of climate change include more frequent and more severe extreme weather and grid reliability are increasingly important. The devasting effects of Winter Storm Elliott from two years ago are telling. On December 23, 2022, this storm caused unplanned natural gas outages that accounted for 23 GW.[43] Afterwards, MISO had to adjust the operating capacity ratings for the Coal Creek Station in North Dakota because Coal Creek Station provided more reliable energy during the storm, operating at maximum capacity to try to cover the outages.[44]

Not only does the reliability of the electrical system play a critical role in sustaining lives and livelihoods in modem society, but so does the affordability of electricity to North Dakota's citizens. The Finalized Rule estimated total compliance costs of $10-14 billion. However, the ND PSC asserts that the combined costs (costs of replacement generation to meet capacity requirements, additional electrical and pipeline transmission costs for the buildout of renewable and new combustion turbine generation, and CCS and hydrogen co-firing technology costs) have a likelihood of $10-14 billion in capital costs solely for North Dakota. Many States and customers are still grappling with payment of customer fees due to deferred costs and ratepayer-backed bonds that try to mitigate the burden on customers.[45]

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[38] Orr, *Forecasting Resource Adequacy in Southwest Power Pool Through 2035.*
[39] *Id.*
[40] Brian Tulloh, Presentation: MISO Updates - Reliability, Transmission, and EPA Regulations to the North Dakota Legislative Assembly (Aug. 7, 2023), **Ex. 8.**
[41] Orr, *Forecasting Resource Adequacy in Southwest Power Pool Through 2035.*
[42] *Id.*
[43] MISO Reliability Subcommittee, Overview of Winter Storm Elliott December 23, Maximum Generation Event (Jan.17,2023),
https://cdn.misoenergy.org/20230I7%20RSC%20Item%2005%20Winter%20Stonn%20Elliott%20Preliminary%20Report627535.pdf
[44] *Id.*
[45] *See* Kansas Corporation Commission Approval of Settlement and Financing to Recover 2021 Winter Storm Costs using Low Interest Bonds. https://www.kcc.ks.gov/news- l 0-13-22; *See also* Matter of Oklahoma Dev. Fin. Auth., 2022 OK 48, ,r 0, 511 P.3d 1048.

Even if the Finalized Rule carved out units capable of 24/7 dispatch with high-capacity factors and allowed these units to operate at lower capacity factors, they would be too costly to operate. If the Finalized Rule causes premature retirements of coal and natural gas units capable of 24/7 dispatch with high-capacity factors because of the cost of investments are not commercially viable, there will be less overall availability of gas and likely more unplanned outages. Success in addressing these issues relies heavily on retaining existing thermal EGUs and delaying the retirements until actual, feasible solutions can be implemented.

The Finalized Rule will increase costs, which, compounded with inflation, will negatively impact the affordability of electric and gas services, resulting in a disproportionate effect on low-income citizens throughout the MISO and SPP regional grids. Given the high rural populations in North Dakota, pricing low-income citizens out of a reliable energy source creates an economic and social justice issue with devasting impacts on North Dakotans' lives.

Section C: Impact of Greenhouse Gas Regulations- Power Plant Economics and Grid Reliability

Power Plant Economic Impacts

The economic impacts for a lignite power plant from the Greenhouse Gas finalized rule will be substantial. Coal-firing power plants, and lignite-firing power plants in particular, may face specific challenges and economic consequences in complying with this regulation, which could result in their forced retirement. Some potential economic impacts include:

1. **Cost of Compliance**: One of the primary concerns for coal power plants is the cost of complying with the EPA regulations. Implementing measures to reduce greenhouse gas emissions, such as installing carbon capture and storage technology or switching to cleaner energy sources, requires significant capital investment. This can increase operating costs and reduce profitability for coal plants.

2. **Reduced Competitiveness**: Compliance with EPA regulations can make coal-fired electricity generation less competitive compared to alternative energy sources, such as natural gas or renewables. Coal plants may struggle to compete in electricity markets where cleaner and more cost-effective alternatives are available, leading to decreased market share and revenue.

3. **Closure of Coal Plants**: In some cases, the economic burden of compliance with EPA regulations may lead to the closure of coal power plants, particularly older and less efficient ones. Plant closures can have severe economic consequences for communities that rely on

them for employment and tax revenue, leading to job losses and economic decline in affected areas.

4. **Increased Electricity Prices**: Compliance costs associated with EPA regulations can result in higher electricity prices for consumers. As coal plants incur additional expenses to meet emission standards, these costs may be passed on to electricity consumers through higher utility bills. This can impact households and businesses, particularly those with limited financial resources.
5. **Impacts on Supply Chains**: The closure of coal power plants can also affect supply chains and related industries that support coal mining, transportation, and plant operations. Reduced demand for coal can lead to job losses in these sectors, further exacerbating the economic downturn in coal-dependent regions.
6. **Regional Economic Disparities**: The negative economic impacts of EPA greenhouse gas regulations on coal power plants are often concentrated in specific regions that are heavily reliant on coal production and electricity generation. These regions may experience disproportionate economic hardship compared to areas with more diversified economies.
7. **Cost Overruns:** The construction of carbon capture facilities involves significant capital investment, and under constrained conditions, there's a higher risk of cost overruns. Limited availability of skilled labor, materials, and equipment can lead to delays, project inefficiencies, and increased construction costs, ultimately driving up the overall cost of implementing carbon capture technology.
8. **Economic Viability:** The high cost of carbon capture technology, coupled with limited resources and tight timelines, may render some coal plants economically unviable. Power plant operators may face difficult decisions about whether to proceed with costly retrofit projects or retire aging coal units altogether. This could have economic ramifications for affected communities, including job losses, reduced tax revenue, and impacts on local economies.
9. **Competitiveness:** Mandating carbon capture technology at every coal plant could affect the competitiveness of coal-fired electricity generation compared to other energy sources. If the cost of compliance exceeds the economic viability of coal plants, it could accelerate their retirement and shift electricity generation towards alternative fuels or technologies, potentially impacting energy affordability and reliability.
10. **Supply Chain Constraints:** Limited availability of critical materials and components for carbon capture projects, such as specialized equipment, absorbents, or construction materials, can lead to supply chain bottlenecks and price volatility. This can further exacerbate cost pressures and project delays, as power plant operators compete for scarce resources in a constrained market.

11. **Permitting Challenges:** Obtaining the necessary permits for constructing carbon capture facilities can be a time-consuming and complex process, involving regulatory approvals at the federal, state, and local levels. Limited permitting timelines can hinder project development and increase uncertainty for investors, delaying the deployment of carbon capture technology and prolonging reliance on higher-emission energy sources.

12. **Job Creation and Retention:** While the deployment of carbon capture technology has the potential to create new jobs in engineering, construction, and operations, workforce shortages and skills gaps may limit job creation opportunities. Moreover, the transition away from coal-fired generation could result in job losses in coal mining, power plant operation, and related industries, impacting communities that depend on these sectors for employment.

Grid Reliability Impacts

Compliance with the Greenhouse Gas Rule will likely have grid reliability impacts on regional power grids that rely on lignite- or other coal-firing power plants. The impacts on grid reliability for power grids that rely on lignite- or other coal-firing power plants can include:

1. **Retirement of Coal Plants**: Compliance with EPA regulations may lead to the retirement of coal-fired power plants, especially older and less efficient ones that cannot economically meet emission standards. Coal plants have traditionally played a significant role in providing baseload power, which is essential for maintaining grid stability. The retirement of these plants can reduce the overall capacity available on the grid, potentially leading to supply shortages during peak demand periods.

2. **Loss of Dispatchable Capacity**: Coal plants are typically considered dispatchable generators, meaning they can ramp up or down their electricity output relatively quickly to respond to changes in demand or supply fluctuations. As coal plants retire and are replaced by intermittent renewable energy sources like wind and solar, the grid may lose dispatchable capacity. This can make it more challenging to balance supply and demand in real-time, increasing the risk of blackouts or brownouts.

3. **Intermittency of Renewable Energy**: The integration of renewable energy sources such as wind and solar into the grid can introduce variability and intermittency in electricity generation. Unlike coal plants, which can operate consistently, renewable energy generation is dependent on weather conditions and time of day. This variability can pose challenges for grid operators in maintaining grid stability and reliability, particularly during periods of low renewable energy output.

4. **Transmission Constraints**: Compliance with EPA regulations may require changes in the location and distribution of electricity generation facilities, such as building new renewable

energy projects in areas with high renewable potential. This can strain existing transmission infrastructure and lead to transmission constraints, limiting the efficient flow of electricity across the grid and potentially causing reliability issues.

5. **Cost of Grid Upgrades**: Adapting the electric grid to accommodate increased penetration of renewable energy and the retirement of coal plants may require significant investments in grid upgrades and infrastructure enhancements. These costs can be substantial and may ultimately be passed on to electricity consumers through higher utility bills, further exacerbating economic concerns.

6. **Reliability Standards Compliance**: Grid operators are required to comply with reliability standards set by organizations like the North American Electric Reliability Corporation (NERC). Changes in the generation mix and operational practices resulting from EPA regulations may necessitate adjustments to ensure continued compliance with reliability standards. Failure to meet these standards could increase the risk of grid failures and disruptions. Ensuring that power plants remain in compliance with reliability standards during the construction and operational phases of carbon capture projects requires careful planning, coordination, and mitigation measures.

7. **Financial Strain:** The substantial financial burden of implementing carbon capture technology could lead to financial strain on power plant operators. This strain may affect their ability to invest in essential grid maintenance, upgrades, and reliability enhancements.

8. **Resource Allocation:** The significant capital investment required for carbon capture projects may divert resources away from other critical grid infrastructure needs, such as transmission upgrades, grid modernization initiatives, or renewable energy integration efforts. This could result in deferred maintenance or delayed investments in reliability-enhancing projects.

9. **Operational Disruptions:** Retrofitting existing coal plants with carbon capture technology involves complex engineering and construction processes, which may require extended downtime and operational disruptions. These disruptions could impact grid reliability by reducing available generation capacity during the construction period.

10. **Technology Risks:** Carbon capture technology is still in the early stages of development and deployment, with inherent technical risks and uncertainties. Mandating its widespread adoption by a specific deadline could lead to rushed implementation, increasing the likelihood of technical failures, operational inefficiencies, and reliability challenges.

11. **Transition Planning:** The transition to widespread deployment of carbon capture technology requires comprehensive planning and coordination to minimize disruptions to grid reliability. This includes assessing the impact on grid stability, developing contingency

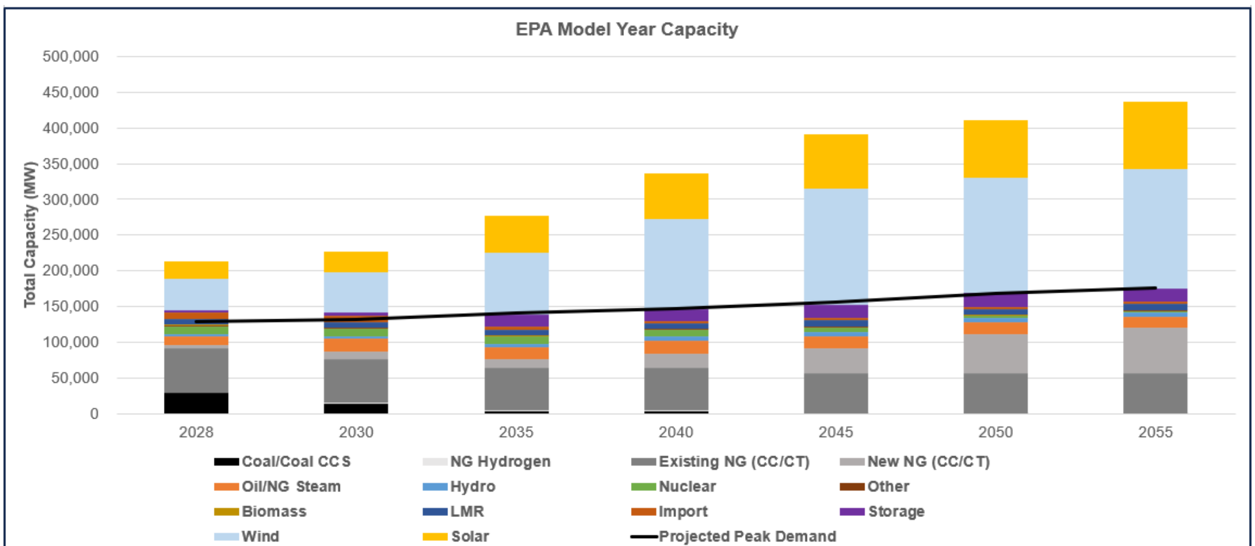
plans for unexpected outages or delays, and ensuring adequate backup capacity during the transition period.

Section D: MISO and SPP Resource Adequacy, Reliability, and Cost Analyses

MISO

Always on Energy Research (AOER) modeled the resource adequacy, reliability, and cost impacts of the finalized carbon rules in the MISO region by evaluating EPA's assumptions in its Regulatory Impact Assessment and associated Integrated Planning Model output files. The Final Rule output files were used to assess total installed capacity, capacity accreditation for each resource, the projected peak demand, and reserve margins.

Figure D-1 shows the installed capacity and projected peak demand for each EPA model year as outlined in the Final Rule output files.



Total Installed Capacity: is calculated using Final Rule Zip File, RPT, Supply Resource Utilization, CapacityTypeDetails, Totaled the capacity in Dispatch Capacity MW for each resource type by model year.

Resource Adequacy Analysis

The analysis below evaluates whether the agency has provided adequate generating resources to meet peak demand based on standard resource adequacy metrics.

Table D-1 shows the capacity accreditation given to new and existing resources for EPA's model run and compares it to the proposed and final rules.

EPA Accreditation: Proposed vs. Final		
Resource	**Proposed Rule**	**Final Rule**
Existing Wind	19%	14%-20%
Existing Solar	55%	19%-24%
New Wind	9%-25%	8%-23%
New Solar	32%-52%	30%-52%
New and Existing Thermal	100%	100%
Existing Hydro	56%	54%
New Hydro	65%	65%
Existing Energy Storage	48%	94%
Pumped Storage	95%	95%
New Battery Storage	100%	100%

Table D-2. Shows the capacity accreditation given to new and existing wind and solar resources by year in EPA's final rules for each model year.

EPA Final Rule Model Year Accreditation for Existing and New Wind and Solar Resources							
Resource	**2028**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**
Existing Wind	14%	14%	14%	20%	20%	20%	20%
New Wind	16%	23%	15%	10%	9%	9%	8%
Existing Solar	24%	24%	24%	19%	19%	19%	19%
New Solar	39%	50%	52%	40%	34%	33%	30%

Figure D-2 shows the projected peak demand, target reserve margin, and capacity stacks for the MISO region after EPA's annual capacity accreditation by resource type is applied to the total installed capacity of the grid.

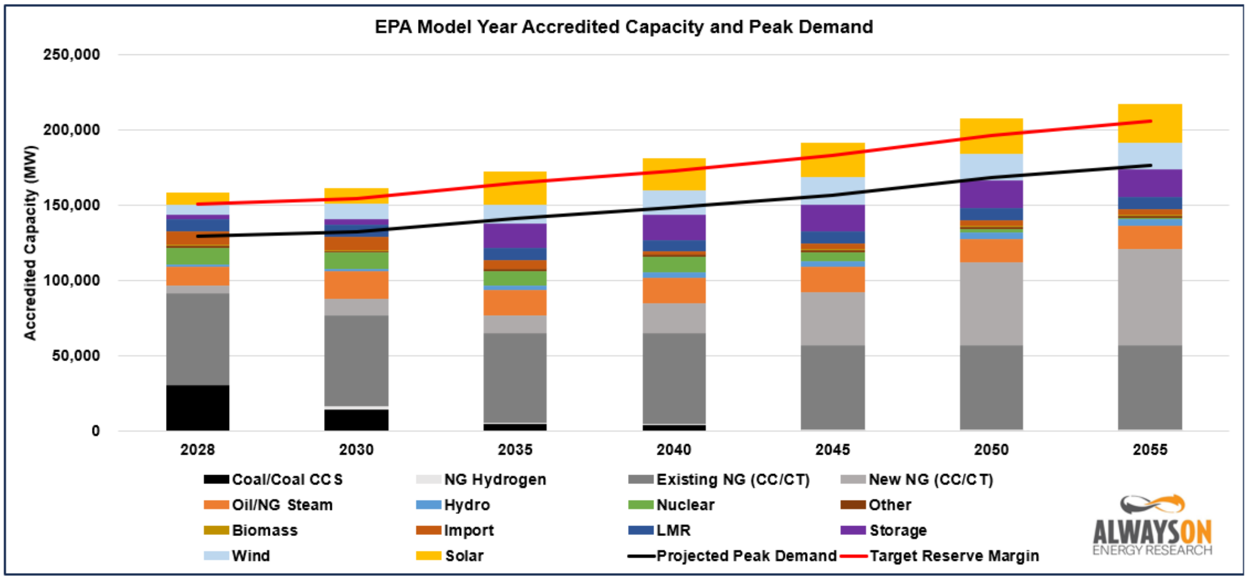


Table D-3 shows the current capacity accreditation by resource type and target reserve margin for the Planning Years 2024-25. Note the seasonal nature of each value.

Seasonal Capacity Accreditation in MISO Planning Year 2024-25				
Season	Wind	Solar	Thermal	Target Reserve Margin
Winter	53.1	5	90	27.4
Spring	18	50	90	26.7
Fall	15.6	50	90	14.2
Summer	18.1	50	90	9

Figure D-3 applies the seasonal accreditation for summer in MISO to the EPA's modeled MISO grid in each model year. Note this projects MISO's capacities into the future when the entity has signaled it will downwardly revise its capacity accreditation for intermittent wind and solar in the future.

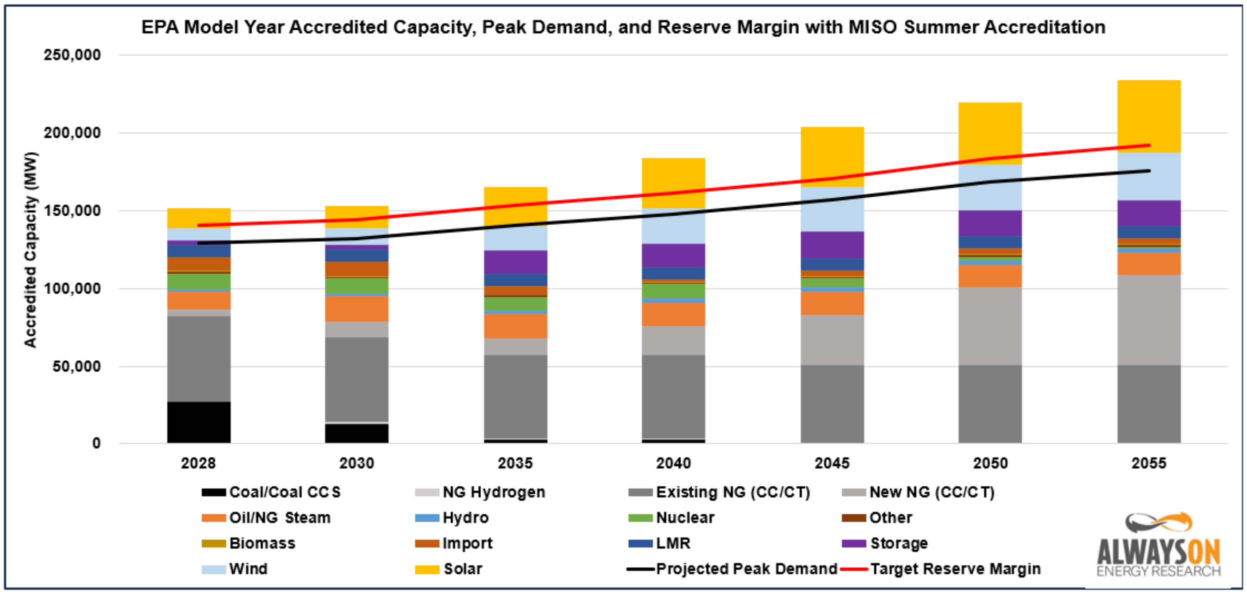


Figure D-4 applies the seasonal accreditation for fall in MISO to the EPA's modeled MISO grid in each model year. Note this projects MISO's capacities into the future when the entity has signaled it will downwardly revise its capacity accreditation for intermittent wind and solar in the future.

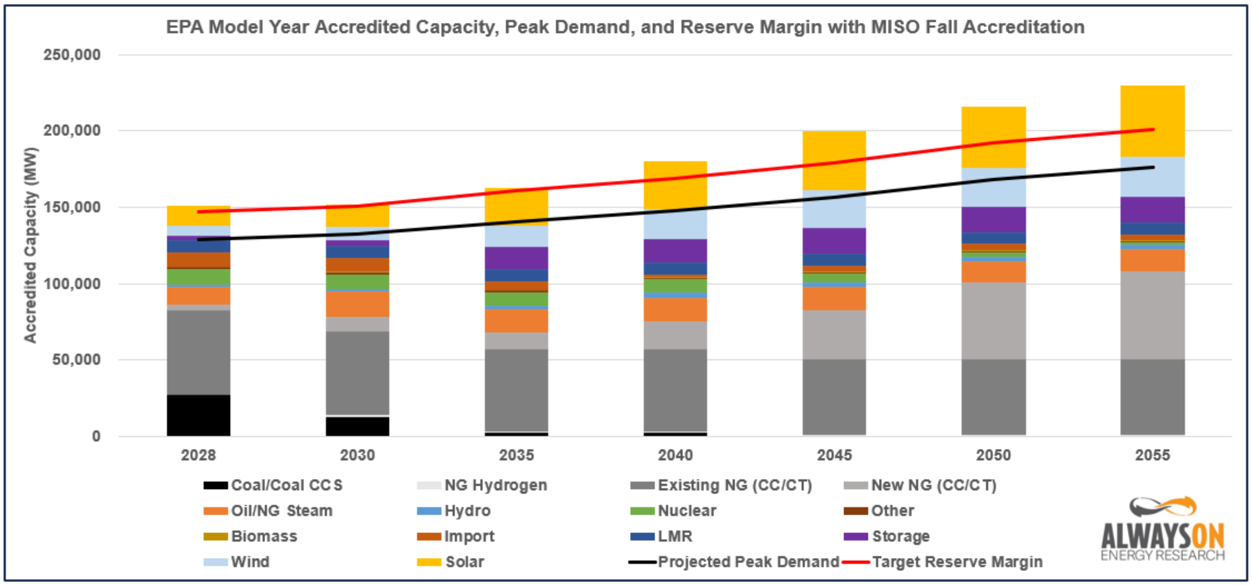


Figure D-5 applies the seasonal accreditation for spring in MISO to the EPA's modeled MISO grid in each model year. Note this projects MISO's capacities into the future when the entity has signaled it will downwardly revise its capacity accreditation for intermittent wind and solar in the future.

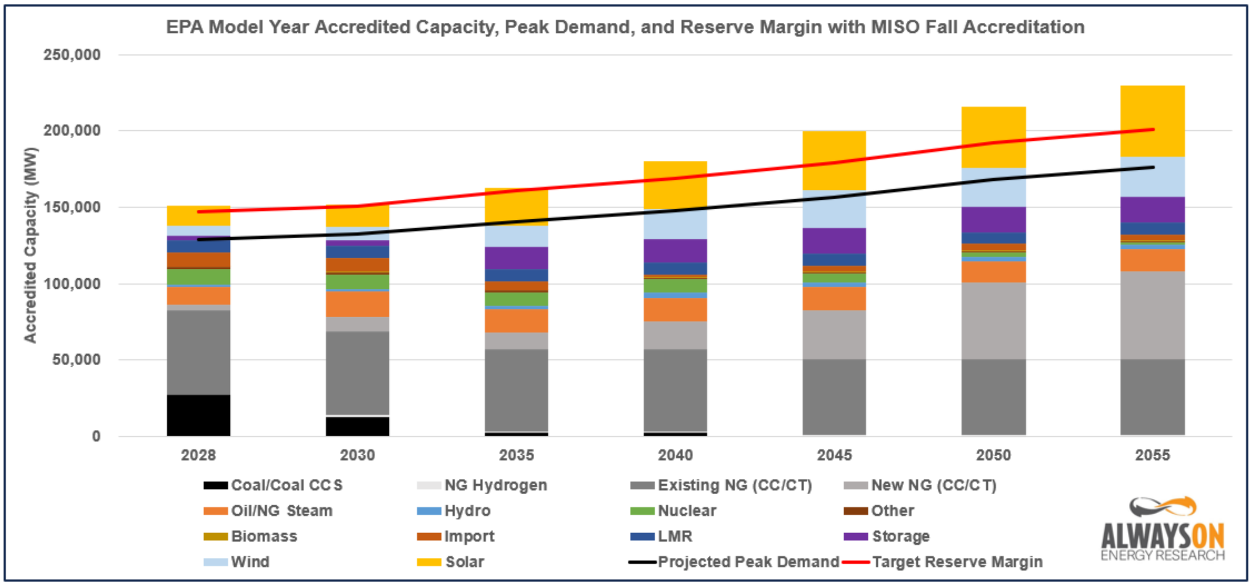
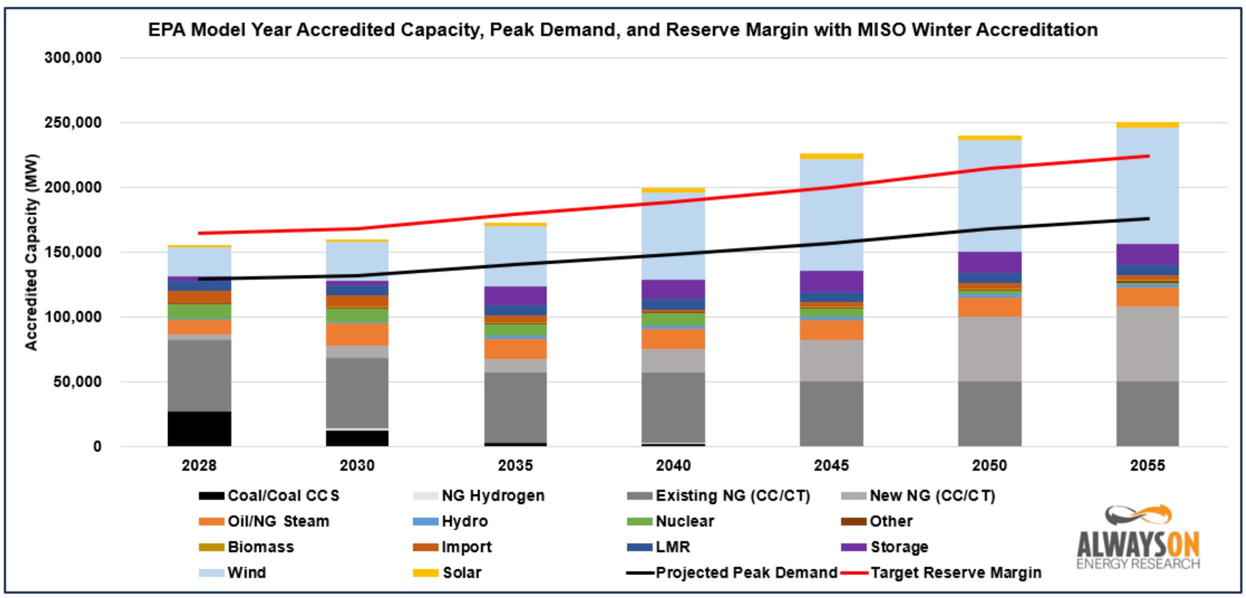


Figure D-6 applies the seasonal accreditation for winter in MISO to the EPA's modeled MISO grid in each model year. Note this projects MISO's capacities into the future when the entity has signaled it will downwardly revise its capacity accreditation for intermittent wind and solar in the future.



Summary Findings: EPA's final rules rely on wind, solar, and battery storage to meet its reserve margin in every year of the model run. These resources would be relied upon to meet projected peak demand in MISO after 2030. This will result in capacity shortfalls if these generators not operating as intended.

Reliability Analysis

AOER conducted a reliability analysis on EPA's modeled generation portfolio in the MISO region under the final carbon rules by using EPA's installed capacity assumptions from the Final Rule output files.

The analysis was conducted by comparing EPA's modeled generation portfolio to the historical hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, 2022, and 2023 to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).

Hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions. This assumption is generous to EPA because it increases the annual output of wind and solar generators to levels that are not generally observed in MISO. Additionally, other policies pursued by the EPA may increase peak load even further, but this additional load was not studied in this analysis.

The analysis replicated EPA's additional reliability mechanisms by allowing greenhouse gas emitting units to run without mitigating emissions to help meet demand during capacity shortfalls and to charge the batteries on the system to reduce the severity of shortfalls. This analysis also used generous assumptions for Load Modifying Resources that did not appear in the EPA's IPM files.

Figure D-7 illustrates that the region would experience capacity shortfalls in the EPA model year 2035 under the 2020 HCY.

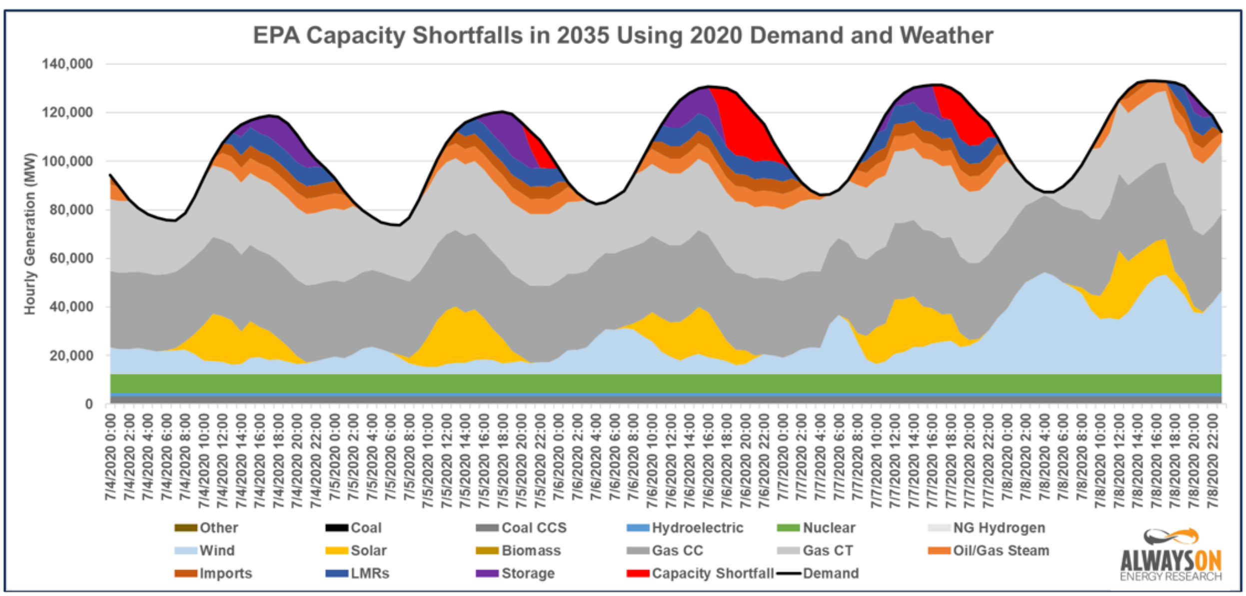
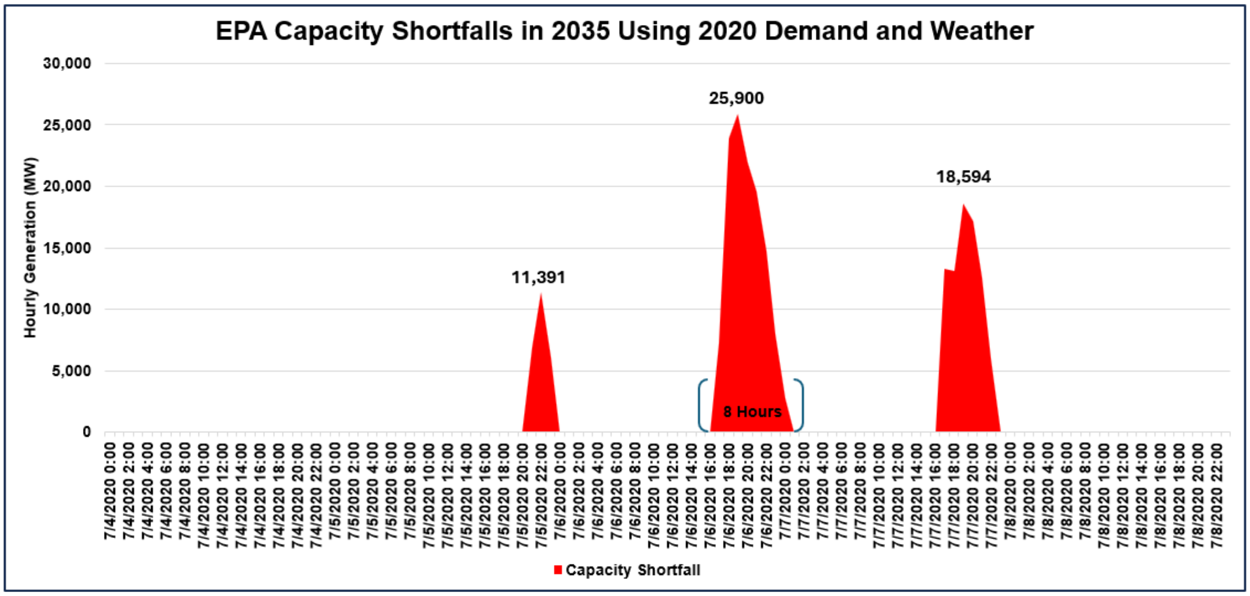


Figure D-8 shows the depths of the capacity shortfalls. The largest shortfall reaches 25,900 MW in July of 2035 based on the 2020 HCY. The shortfall exhibits varying levels of severity and lasts for a total of 8 hours.



The shortfalls occur because wind is operating below EPA's capacity accreditation for the resource (See Figure D-9). This leaves the system short on energy.

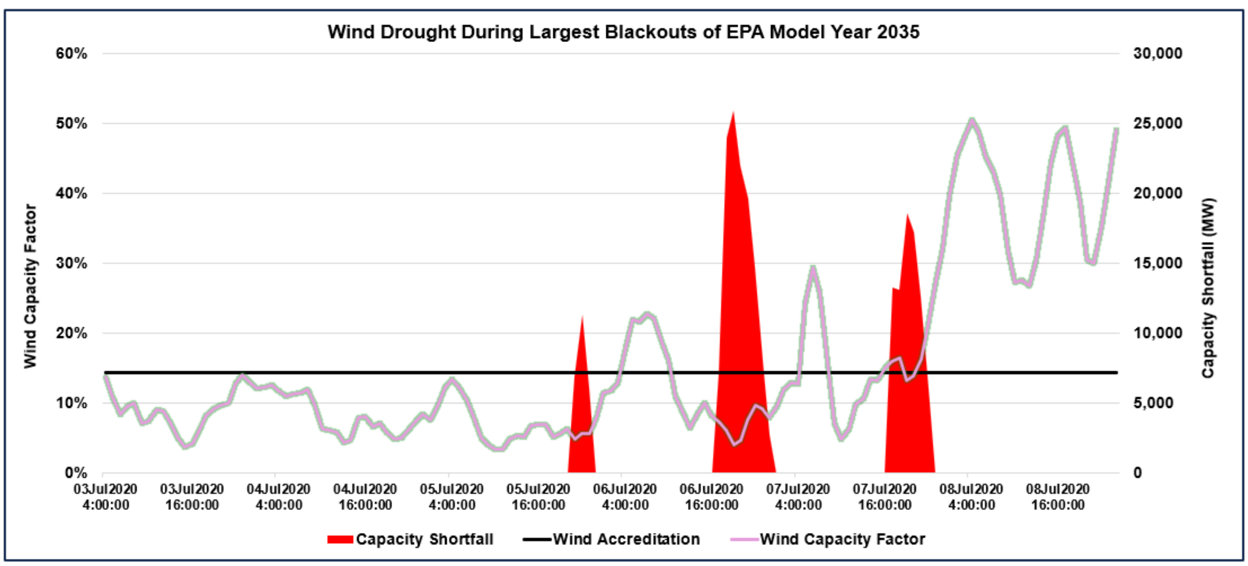


Figure D-10 illustrates that the largest capacity shortfall of 25,900 MW is significant. It would account for 19 percent of MISO PRMR for the 2024-25 Planning Year.

Assessing Severity of the Blackouts

Summer 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,697	13,396	10,787	9,403	8,297	18,565	21,565	8,431	21,888	5,038	N/A	136,067

- The worst capacity shortfall is a 25,900 MW capacity shortfall that would occur in July 2035 using the 2020 HCY.
- For context, this shortfall would account for 19 percent of MISO-wide Planning Reserve Margin Requirement (PRMR) in the 2024 Planning Reserve Auction (PRA).
- This is the nearly the equivalent of MISO Zones 1 and 5 suffering blackouts based on the PRMRs in the PRA.

MISO Resource Adequacy Zones

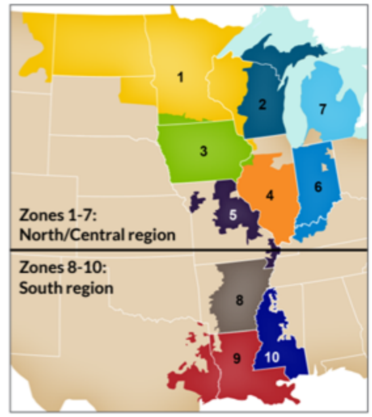


Table D-4 shows the hours of capacity shortfalls on EPA's modeled MISO grid for each of the model years when stress tested against the five HCYs. These values greatly exceed the one day in ten year loss of load expectation (LOLE) and the .1 day (2.4 hours) per year metric that grid planners deem necessary for reliability.[46]

Total Hours of Shortfalls								
Year	**2028**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**Total**
2019	0	0	10	4	4	2	2	22
2020	0	2	17	8	6	3	1	37
2021	0	1	18	0	0	0	0	19
2022	0	0	0	0	0	0	0	0
2023	0	1	16	4	1	0	0	22

Table D-5 shows the number of MWhs of unserved load in each model year and each of the five HCYs.

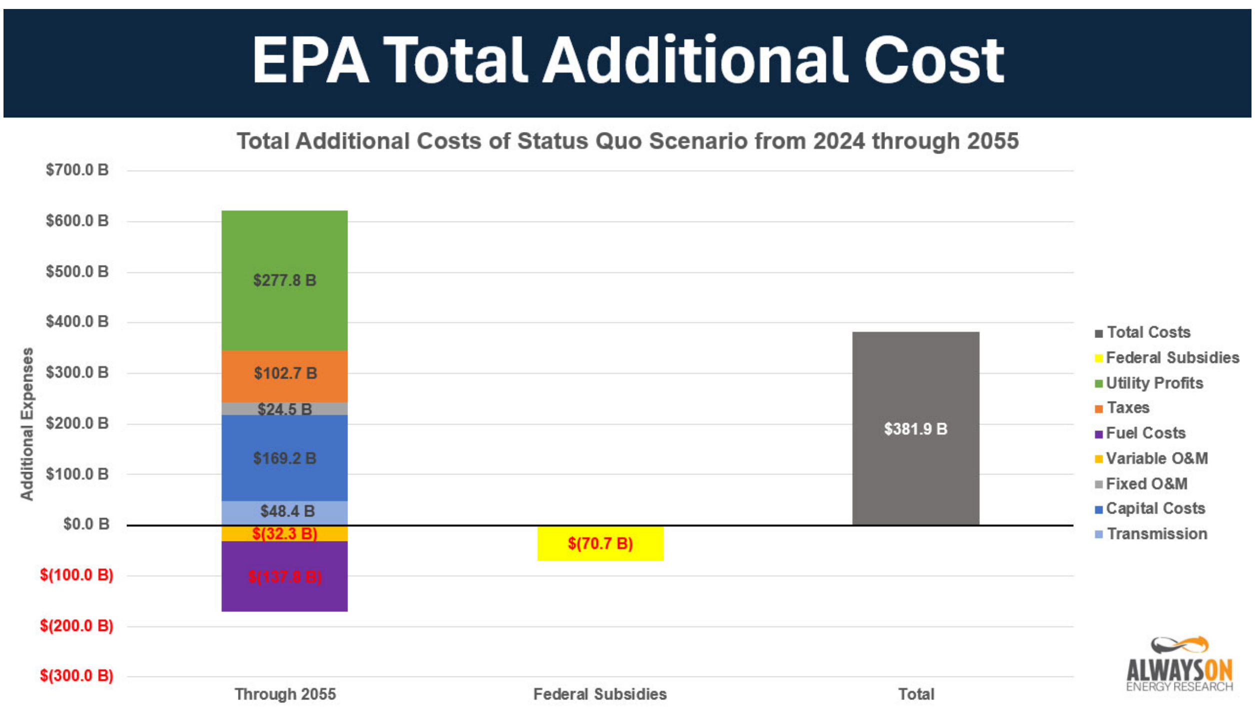
[46] Electric Power Research Institute, Practices and Standards," Resource Adequacy, Accessed May 17, 2024, https://msites.epri.com/resource-adequacy/metrics/practices-and-standards#:~:text=Consider%20a%2010%2Dyear%20time,1%20day%20per%2010%20years.

Total Shortfalls (MWh)								
Year	**2028**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**Total**
2019	0	0	109,888	52,065	39,463	10,660	4,701	216,777
2020	0	3,017	229,235	86,640	48,393	9,081	934	377,300
2021	0	56	129,724	0	0	0	0	129,779
2022	0	0	0	0	0	0	0	0
2023	0	5,880	132,189	21,615	4,917	0	0	164,601

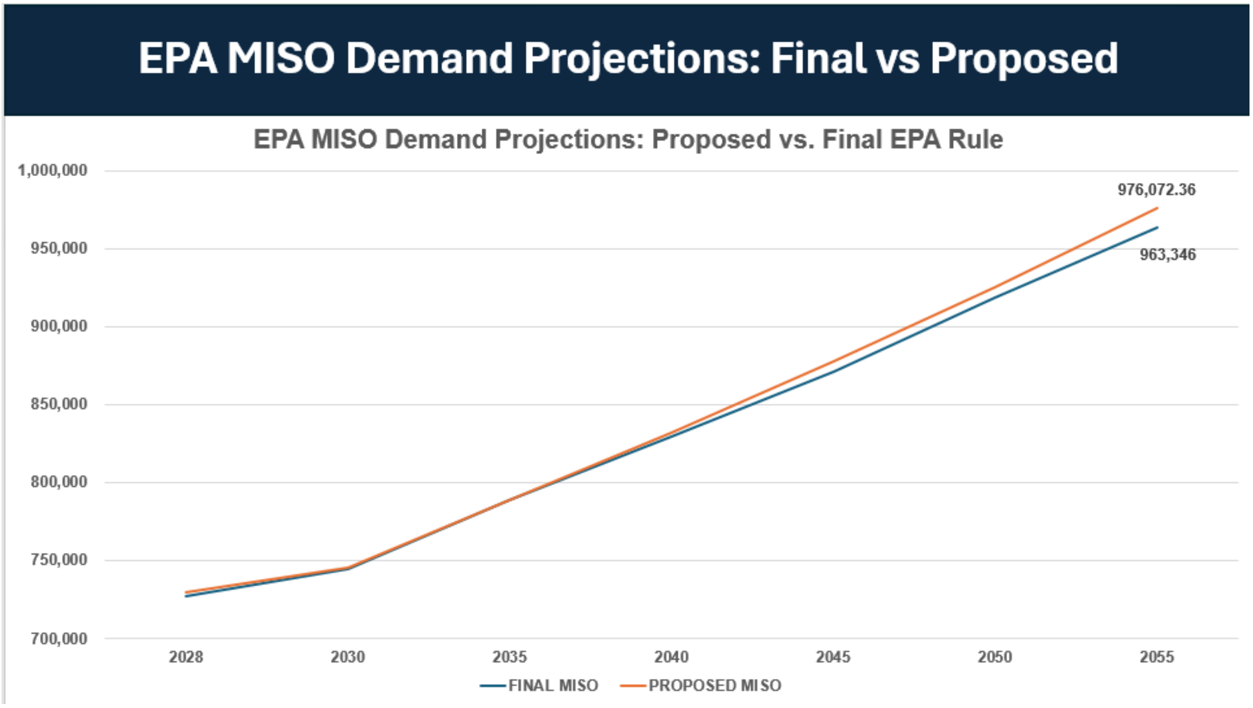
Table D-6 shows the value of lost load (VOLL) by applying MISO's damage factor by the number of unserved megawatt hours on the system for each model year when stress tested against each o the five HCYs.

Value of Lost Load for Each MISO Model Year By Historical Comparison Year								
Year	2028	2030	2035	2040	2045	2050	2055	Total
2019	$0	$0	$1,098,880,000	$520,647,875	$395,628,665	$106,598,673	$47,011,180	$2,168,766,393
2020	$0	$30,169,037	$2,292,350,000	$866,401,675	$483,925,493	$90,814,986	$9,343,828	$3,773,005,019
2021	$0	$555,775	$1,297,240,000	$0	$0	$0	$0	$1,297,795,775
2022	$0	$0	$0	$0	$0	$0	$0	$0
2023	$0	$58,796,196	$1,321,890,000	$216,154,963	$49,167,850	$0	$0	$1,646,009,009

Figure D-11 shows the total cost of implementing EPA's modeled MISO grid compared to the operating costs of the existing MISO grid. The total cost is an additional $381.9 billion after fuel savings and subsidies are applied to the total cost of the fleet transition.



Interestingly, EPA downwardly revised its total energy consumption estimates in the final rules compared to the proposed rules. This assumption is at odds with estimates for growing demand for electricity due to data centers and reshoring of manufacturing (See Figure D-12).

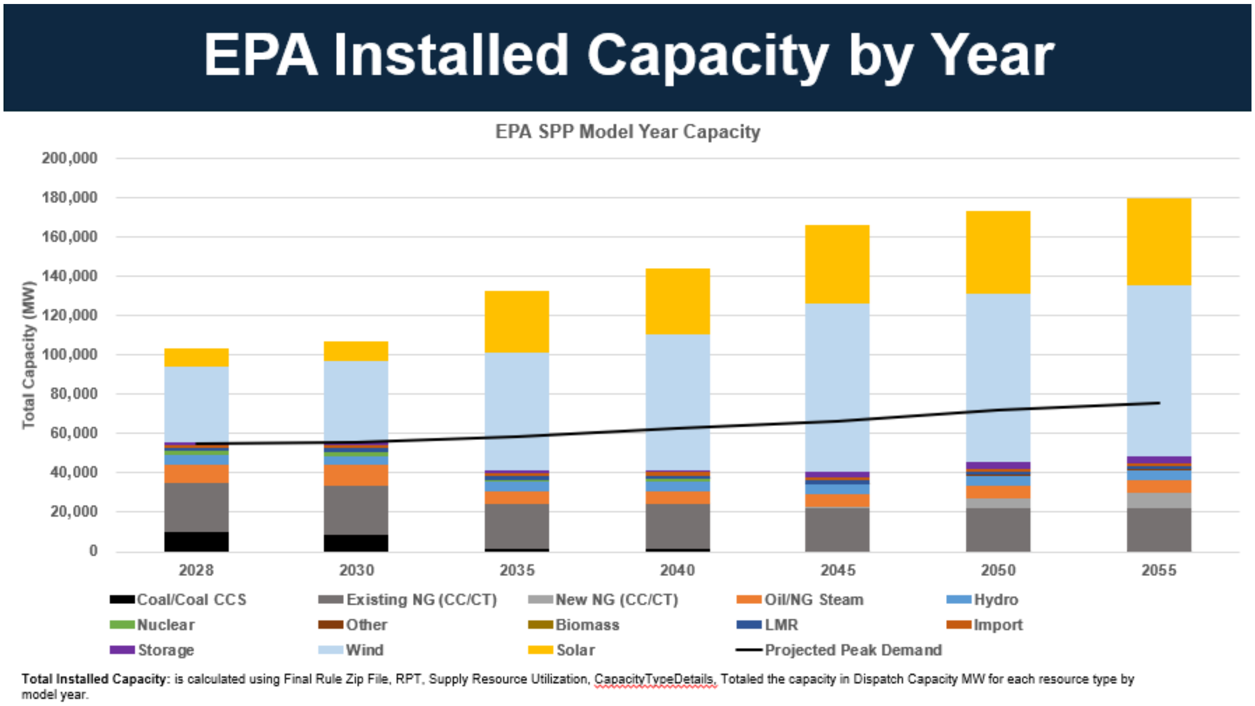


SPP

Always on Energy Research (AOER) modeled the resource adequacy, reliability, and cost impacts of the finalized carbon rules in the SPP region by evaluating EPA's assumptions in its Regulatory Impact Assessment and associated Integrated Planning Model output files. The Final Rule output files were used to assess total installed capacity, capacity accreditation for each resource, the projected peak demand, and reserve margins.

Resource Adequacy

Figure D-13 shows the installed capacity and projected peak demand for each EPA model year as outlined in the Final Rule output files. EPA's modeled SPP grid relies on wind and solar to meet projected peak demand targets. Furthermore, EPA assumes SPP will be a net exporter of capacity.



Total Installed Capacity: is calculated using Final Rule Zip File, RPT, Supply Resource Utilization, CapacityTypeDetails, Totaled the capacity in Dispatch Capacity MW for each resource type by model year

Table D-7. EPA continues to use unrealistically high capacity accreditations for new and existing thermal plants and new and existing wind, solar, and battery storage.

EPA continues to give new and existing wind and solar resources different accreditations despite a 2019 report from SPP which shows that increasing penetration of solar resources causes the accredited percentage of capacity related to nameplate of each individual resource to decrease.

Final SPP EPA Accreditation	
Resource	**Final Rule**
Existing Wind	10%
Existing Solar	82%
New Wind	14%-52%
New Solar	83%-100%
New and Existing Thermal	100%
Existing Hydro	76%
New Hydro	65%
Existing Energy Storage	100%
Pumped Storage	95%
New Battery Storage	100%

Table D-8. EPA continues to give new and existing wind and solar resources different accreditations.

EPA gives new and existing solar resources unrealistic capacity accreditations above 80 percent. **EPA's solar capacity accreditations are irresponsibly high**.

SPP EPA Final Rule Model Year Accreditation for Existing and New Wind and Solar Resources							
Resource	**2028**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**
Existing Wind	10%	10%	10%	10%	10%	10%	10%
New Wind	14%	52%	21%	26%	18%	18%	19%
Existing Solar	82%	82%	82%	82%	82%	82%	82%
New Solar	100%	100%	84%	84%	83%	83%	83%

Figure D-14. Shows SPP resource adequacy calculations based on EPA's capacity values shown in Table D-7 when applied to EPA's modeled SPP grid in Figure D-13.

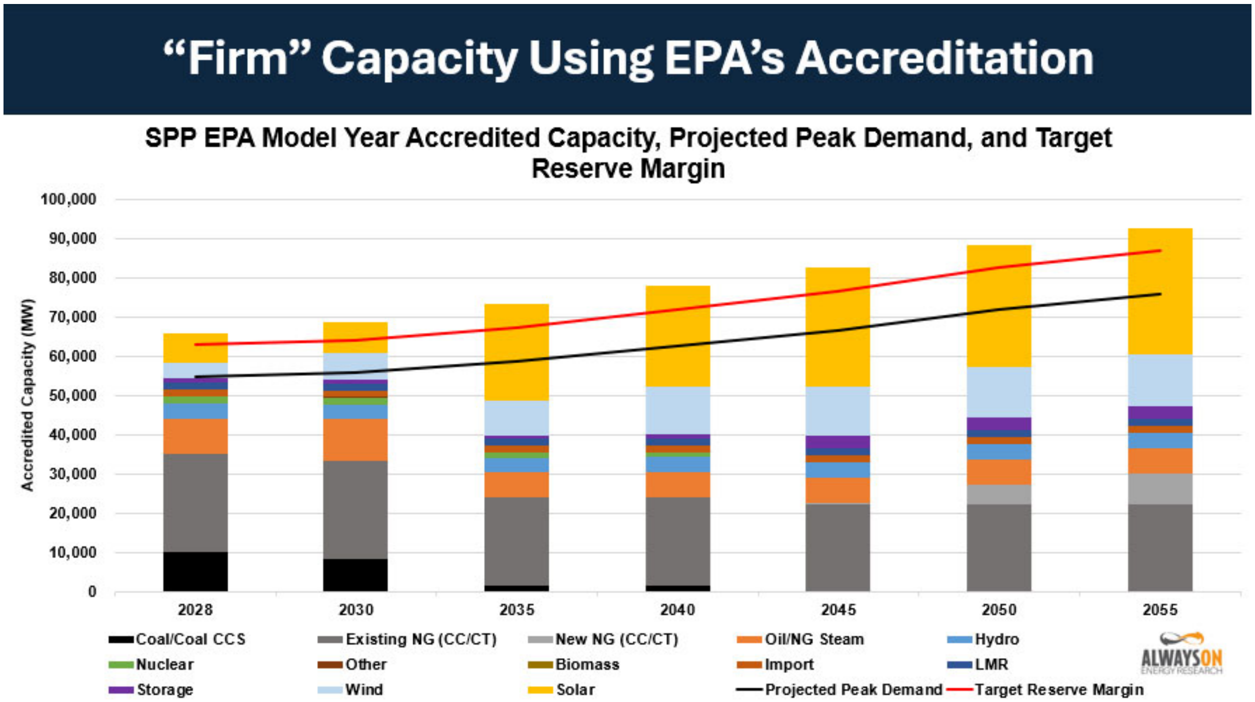


Table D-9. SPP is in the process adopting the use of Effective Load Carrying Capacity (ELCC) for wind, solar, and battery storage accreditation.

These analyses show increasing penetration of wind, solar, and battery storage resources causes the accredited percentage of capacity related to nameplate of each individual resource to decrease.

Wind accreditation is based off SPP's 2022 analysis of the ELCC at 40,000 MW and held constant through the model run.

Solar accreditation is based of SPP's 2020 analysis of the solar ELCC at 20,000 MW of penetration and this value is held constant through the model run.

Battery storage accreditation is based off the 2022 ELCC Study for Energy Storage Resources. The model uses the accreditation at the 1,000 MW battery storage values for model years 2028 – 2040, which are 100% in the summer and 83% in the winter, and the at the 3,000 MW of 4-hour battery storage values from 2045-2055.

SPP Capacity Accreditation By Resource			
Season	Wind	Solar	Battery Storage 3,000 MW
Summer	15	40	96
Winter	16	6	71

Figure D-15 shows EPA's modeled SPP grid from Figure 13 when SPP's summer capacity accreditation values for wind, solar, and battery storage are applied to the generation fleet.

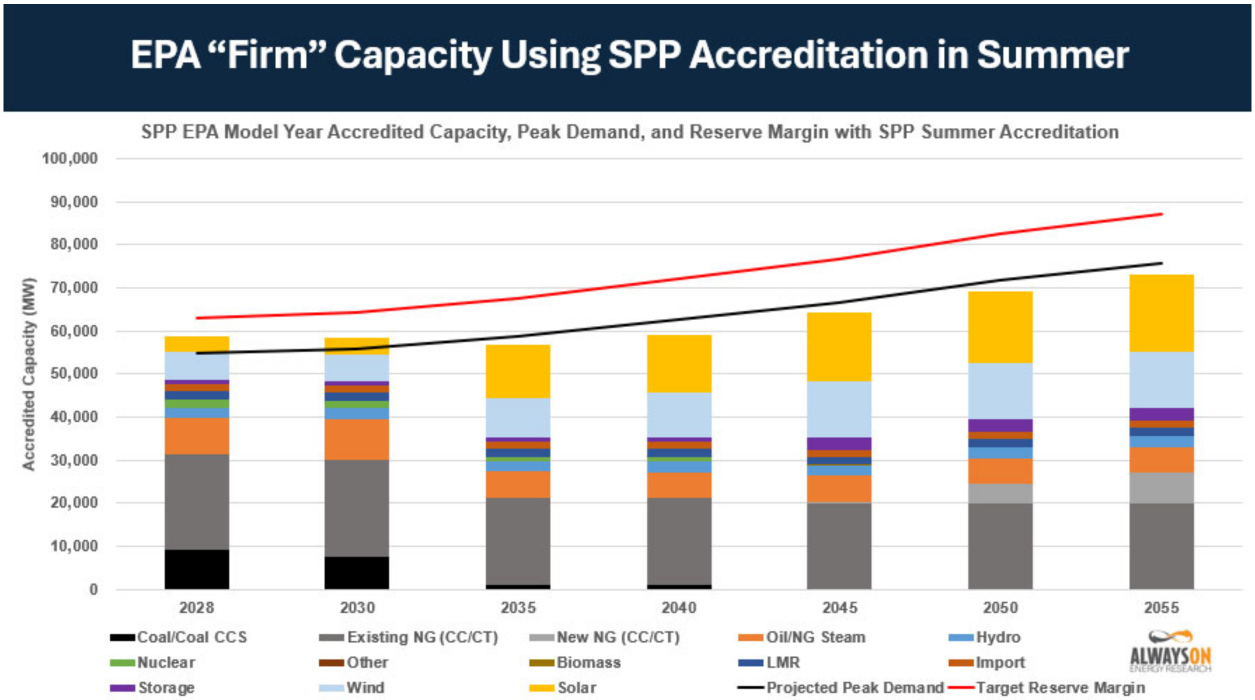
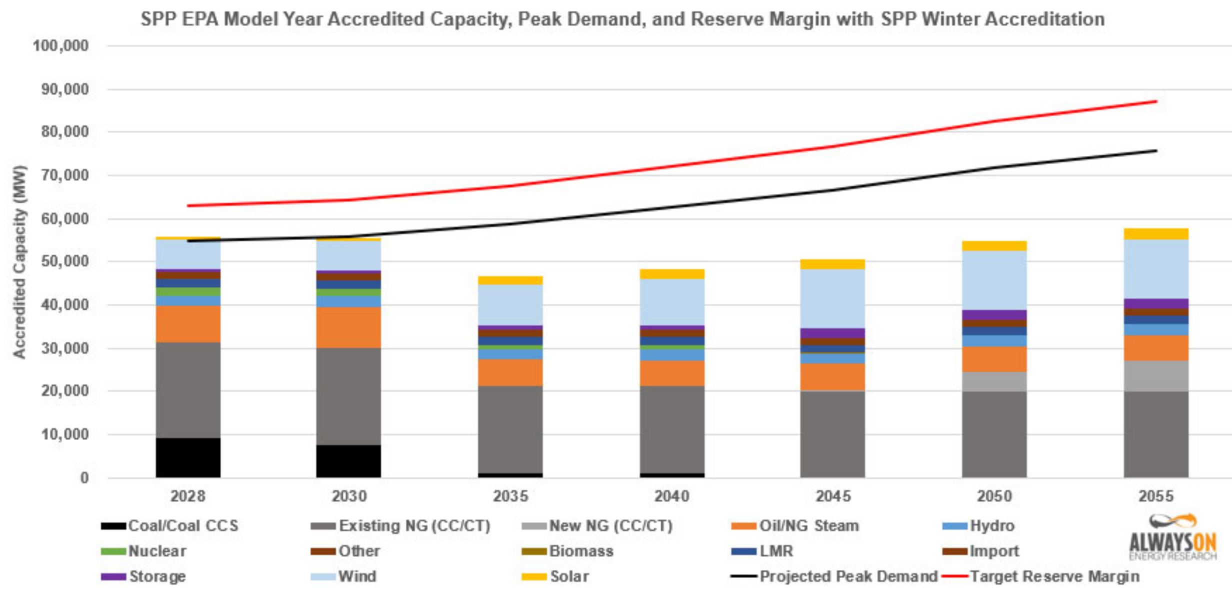


Figure D-16 shows EPA's modeled SPP grid from Figure 13 when SPP's winter capacity accreditation values for wind, solar, and battery storage are applied to the generation fleet.

EPA Accredited Capacity Using SPP Accreditation in Winter



Reliability

AOER conducted a reliability analysis on EPA's modeled generation portfolio in the SPP region under the final carbon rules by using EPA's installed capacity assumptions from the Final Rules datafiles.

The analysis was conducted by comparing EPA's modeled SPP generation portfolio to the historical hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, 2022, and 2023 to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).

Hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions.

This assumption is generous to EPA because it increases the annual output of wind and solar generators to levels that are not generally observed in SPP on a fleet-wide basis.

Additionally, other policies pursued by the EPA may increase peak load even further, but this additional load was not studied in this analysis.

The analysis replicated EPA's additional reliability mechanisms by allowing greenhouse gas emitting units to run without mitigating emissions to help meet demand during capacity shortfalls and to charge the batteries on the system to reduce the severity of shortfalls.

Will EPA's modeled SPP grid be able to meet demand based on these observed, real-life model inputs?

Figure D-17 shows thirteen separate capacity shortfalls would occur from February 7, 2040 through February 19 2040 using 2021 hourly electricity demand profiles and wind and solar hourly generation data.

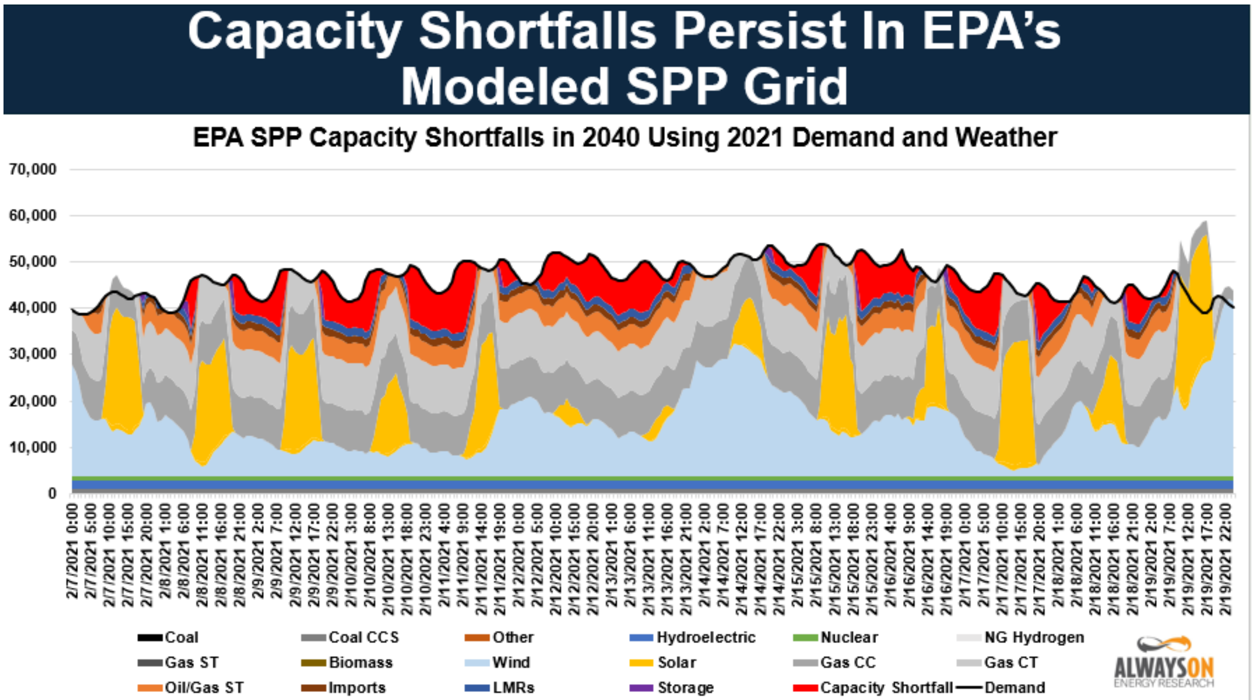


Figure D-18 shows the largest capacity shortfall, observed on February 11th, would hit nearly 15,000 MW. The longest capacity shortfall would last for 41 straight hours spanning from February 12th rough February 13th. Note, this is the same weather year as Winter Storm Uri.

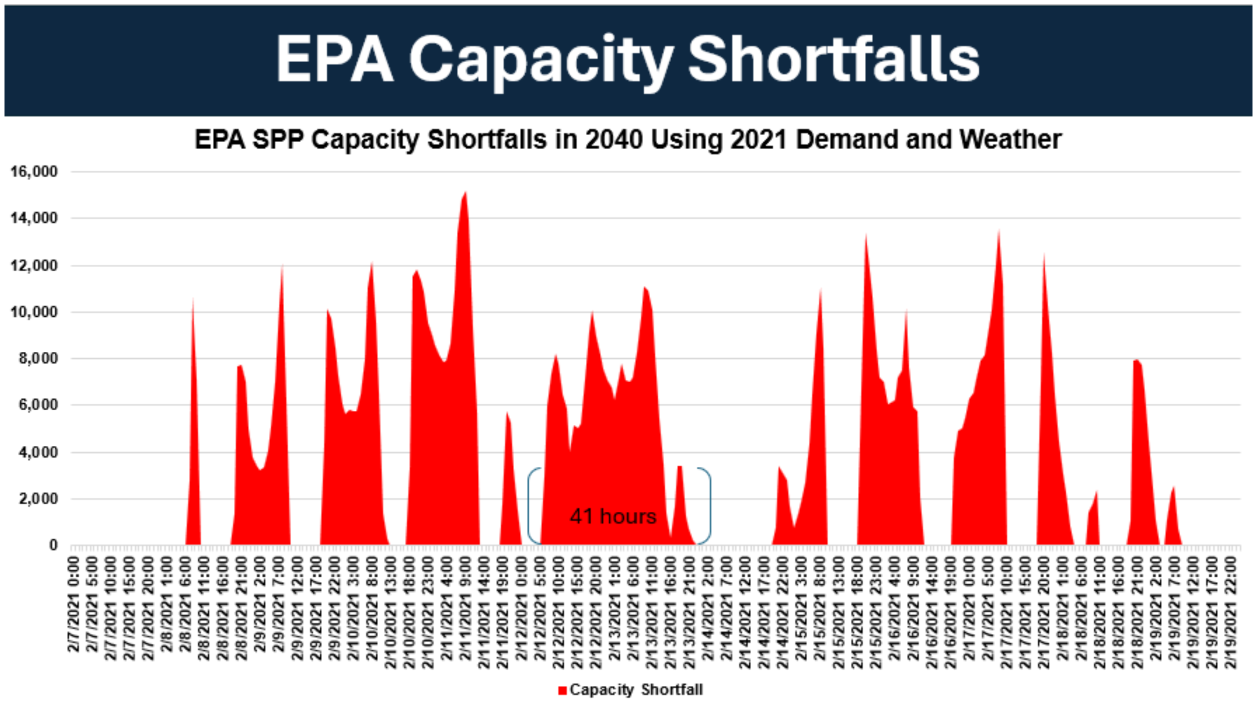


Figure D-19 shows the blackouts primarily occur during the evening hours because EPA's modeled SPP grid relies too heavily on solar to meet peak demand and its target reserve margin. Furthermore, there is far too little dispatchable capacity in the footprint to meet demand even when disregarding EPA's emissions limits and allowing generators to run at full capacity.

During the longest blackout, solar is operating far below EPA's accredited capacity value for the resource.

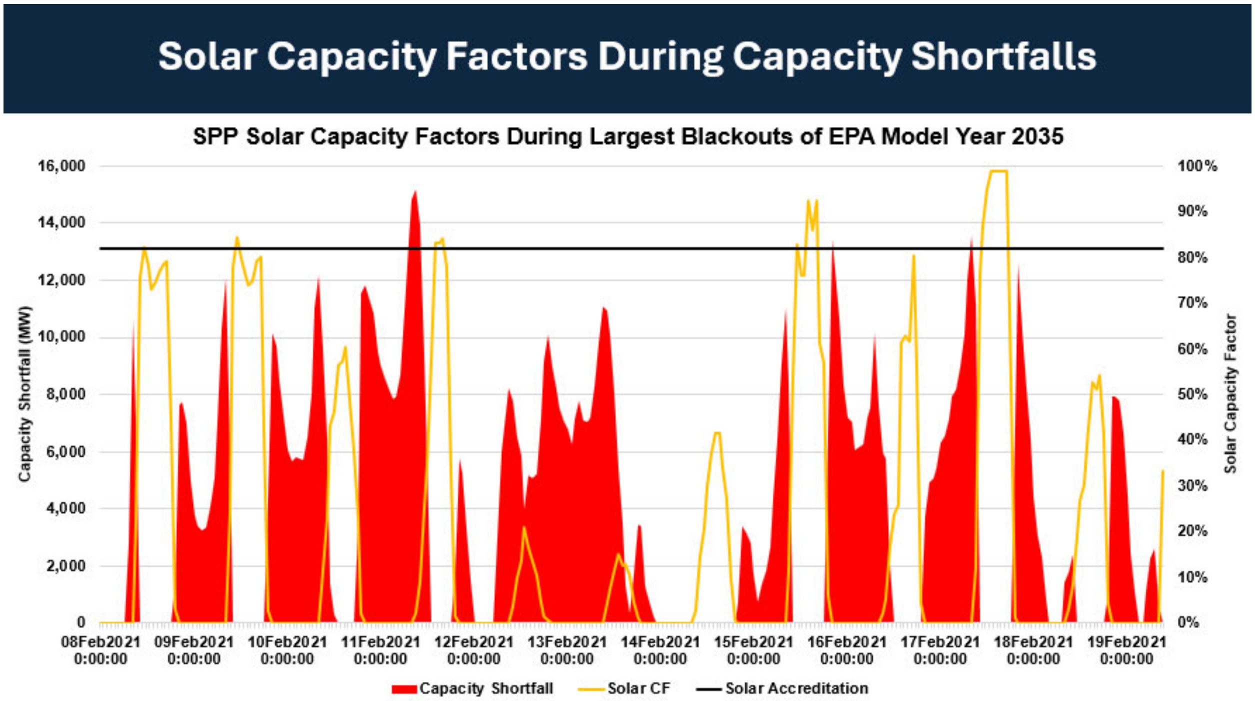


Table D-10. For context, the largest capacity shortfall of around 15,000 MW would account for 27 percent of SPP-wide forecast Net Peak Demand for 2024.

Southwest Power Pool, Inc.

Table 1: SPP 2023 to 2028 Summer Season Outlook

Demand Summary *(Units – MW)*	2023	2024	2025	2026	2027	2028
Total LRE Forecasted Net Peak Demand	53,954	54,661	55,575	56,270	57,256	57,552
Controllable and Dispatchable Demand Response[6]	829	1,353	1,489	1,772	1,798	1,807
Energy Efficiency and Conservation	249	324	384	435	480	517
Stand-by Load Under Contract	25.4	25.4	25.4	25.4	25.4	25.4
Capacity Summary *(Units – MW)*	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Total Capacity[7]	64,822	63,380	63,357	61,707	59,630	57,430
Capacity Resources[6]	64,076	64,746	64,980	64,765	63,740	62,651
Confirmed Retirements	122	382	382	382	382	382
Unconfirmed Retirements	0	1,878	2,155	3,610	4,603	5,719
Other Capacity Adjustments – Additions	0	0	0	0	0	0
Other Capacity Adjustments – Reductions	128	128	128	128	128	128
External Firm Capacity Purchases	259	304	324	344	344	349
External Firm Capacity Sales	617	592	592	592	592	592
External Firm Power Purchases	1,355	1,355	1,354	1,354	1,295	1,295
External Firm Power Sales	0	0	0	0	0	0
SPP BA Area Planning Reserve[8]	20.1%	19.4%	17.9%	16.1%	12.2%	9.7%
Planning Reserve Margin *(As specified in SPP Planning Criteria)*	15%	15%	15%	15%	15%	15%
Total LRE Resource Adequacy Requirement	61,970	62,783	63,828	64,627	65,761	66,102
Total LRE Excess Capacity	2,784	1,694	904	-166	-2,964	-4,389
Total Generator Owner Excess Capacity *(Excludes Generator Owner uncommitted Deliverable Capacity of wind resources)*	67	781	780	856	1,436	1,436

[6] Demand Response Accredited MW is up 381 MW from the 2022 submittals. Over the next 5 years the accredited amount is expected to increase by approximately 1,000 MW.

[7] The Total Capacity and Capacity Resource values contain the Firm Capacity and Deliverable Capacity from LREs and Generator Owners. The equation for calculating the Total Capacity is as follows: Capacity Resources – Confirmed Retirements – Unconfirmed Retirements + Other Capacity Adjustments (Additions) – Other Capacity Adjustments (Reductions) + External Firm Capacity Purchases – External Firm Capacity Sales + External Firm Power Purchases – External Firm Power Sales

[8] The SPP BA Area Planning Reserve is calculated by dividing the difference between the (Total Capacity + Unconfirmed Retirements) and the Total LRE Forecasted Net Peak Demand by the Total LRE Forecasted Net Peak Demand.

Table D-11 shows the total hours of capacity shortfalls in each model year when compared to the historical weather year. These values greatly exceed the one day in ten year loss of load expectation (LOLE) and the .1 day (2.4 hours) per year metric that grid planners deem necessary for reliability.[47]

Total Hours of Shortfalls								
Year	2028	2030	2035	2040	2045	2050	2055	Total
2019	2	5	56	94	82	63	61	363
2020	0	0	41	63	53	45	39	241
2021	2	6	220	300	298	271	268	1,365
2022	1	27	116	183	153	144	143	767
2023	30	47	121	182	140	134	132	786

Table D-12 shows the total megawatt hours of capacity shortfalls in each model year when compared to each historical weather year.

Total Shortfalls (MWh)								
	2028	2030	2035	2040	2045	2050	2055	Total
2019	2,336	11,481	157,389	327,854	332,649	275,613	271,183	1,378,505
2020	0	0	122,456	232,589	243,625	190,871	189,259	978,800
2021	1,466	12,052	958,204	1,527,581	2,007,625	1,895,291	1,896,587	8,298,806
2022	604	27,668	467,164	843,236	914,724	880,436	903,176	4,037,008
2023	77,714	149,382	428,164	751,748	666,098	660,846	704,685	3,438,637

Table D-13 shows the value of lost load (VOLL) which multiples the number of unserved megawatt hours by $10,000. These values indicate massive costs of blackouts in the region. In Model Year 2045 using the 2021 the social cost of blackouts would be $20 billion, approximately half of the entire gross domestic product of Vermont ($43 billion).

Value of Lost Load								
Year	2028	2030	2035	2040	2045	2050	2055	Total
2019	$23,360,000	$114,810,000	$1,573,890,000	$3,278,543,170	$3,326,490,000	$2,756,130,000	$2,711,830,000	$13,785,053,170
2020	$0	$0	$1,224,560,000	$2,325,892,042	$2,436,250,000	$1,908,710,000	$1,892,590,000	$9,788,002,042
2021	$14,660,000	$120,520,000	$9,582,040,000	$15,275,814,637	$20,076,250,000	$18,952,910,000	$18,965,870,000	$82,988,064,637
2022	$6,040,000	$276,680,000	$4,671,640,000	$8,432,358,668	$9,147,240,000	$8,804,360,000	$9,031,760,000	$40,370,078,668
2023	$777,140,000	$1,493,820,000	$4,281,640,000	$7,517,477,459	$6,660,980,000	$6,608,460,000	$7,046,850,000	$34,386,367,459

Figure D-20 shows the total additional cost of implementing EPA's modeled MISO grid compared to the operating costs of the existing SPP grid. The total cost is an additional $65.6 billion after fuel savings and subsidies are applied to the total cost of the fleet transition

[47] Electric Power Research Institute, Practices and Standards," Resource Adequacy, Accessed May 17, 2024, https://msites.epri.com/resource-adequacy/metrics/practices-and-standards#:~:text=Consider%20a%2010%2Dyear%20time,1%20day%20per%2010%20years.

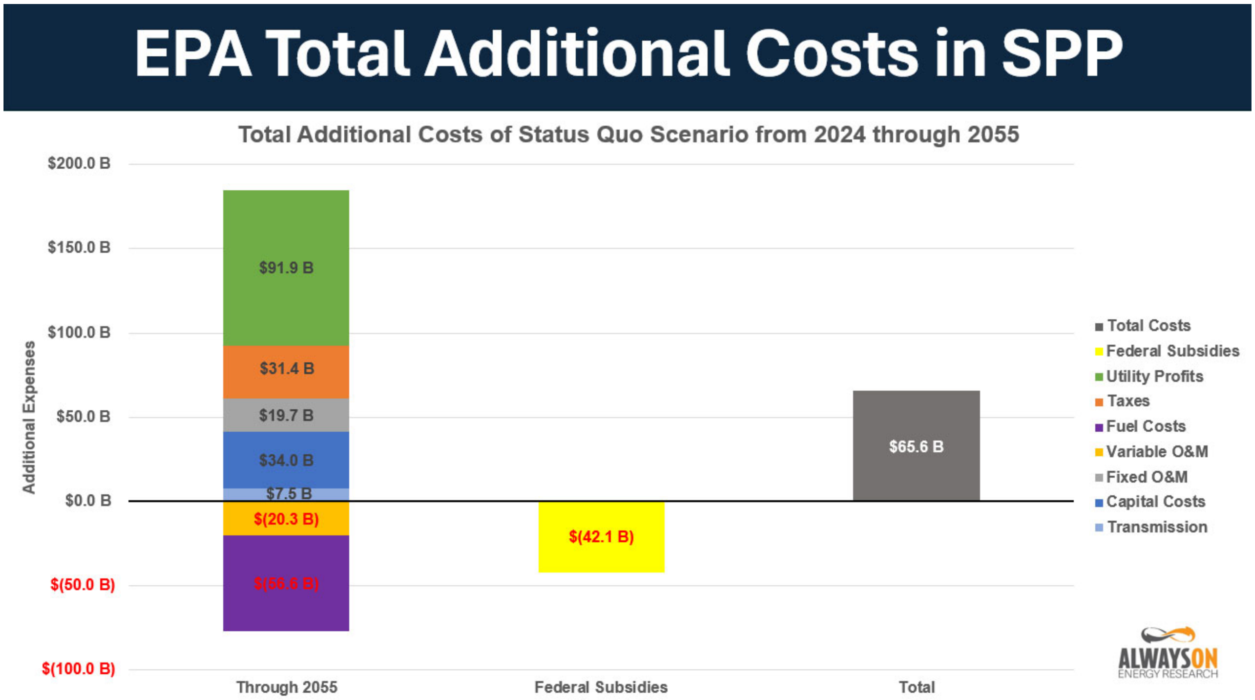


Figure D-21 shows EPA downwardly revised the electricity consumption estimates in SPP in the final rule output files relative to the proposed rules. This assumption is at odds with estimates for growing demand for electricity due to data centers and reshoring of manufacturing