service requirements of its Montana customers[,]" § 69-3-1204(2)(a)(i), MCA.

6. The Rule introduces significant economic uncertainty for important electricity generating units ("EGUs") in the portfolio of electricity resources serving Montana residents and businesses and underpinning the export of electricity to utilities across the pacific northwest region of states. The Rule also limits the options for adding new generation to serve existing and new electricity demand in Montana. Specifically, the Rule requires major modifications to the existing Colstrip Units 3 and 4 in Rosebud County, Montana.

7. Colstrip Units 3 and 4 are coal-fired steam generating units, each with a nameplate generating capacity of 740 megawatts. The units are operated by Talen Montana and currently serve residential and commercial customers of NorthWestern Energy in Montana, large industrial customers of Talen Montana, as well as electricity customers of utilities with service territories including parts of Idaho, Washington, and Oregon. The units play an integral role in maintaining operation of the NorthWestern Balancing Authority in Montana, especially during peak electricity demand events. NorthWestern Energy, a thirty percent

owner of Unit 4 has announced plans to acquire Avista Corporation's fifteen percent shares in Units 3 and 4, effective January 1, 2026. NorthWestern's depreciation schedule for its current share of Unit 4 runs through 2042.

8. The Rule's requirement of 90 percent carbon capture has not been adequately demonstrated as required of the best system of emission reduction (BSER) in Section 111 of the Clean Air Act. In addition to the degree of emission limitation available through application of BSER, the cost of achieving the reduction must be considered. Carbon capture and sequestration/storage (CCS) has been extremely expensive to implement and operate. Two examples of failed CCS operations are the Kemper CCS site in Mississippi (not operating on coal any longer) and the Petra Nova CCS site in Texas. One site that is still operating is the Boundary Dam CCS project in Canada which, at best, operates at a 65% carbon capture and cost $4.2 million per megawatt (MW). If this cost was scaled to the MW ratings of the Colstrip units, capital costs would be in the billions of dollars, not to mention the parasitic loads which are required for capturing the carbon dioxide - most likely in an absorption tower that requires significant heating and cooling operations.

9. A 2016 report from the US Department of Energy (DOE) predicted as much as $3 billion to retrofit the Colstrip units as a preliminary cost estimate; scaling the $4.2 million per MW from Boundary Dam to Colstrip suggests that capital costs could be as high as $15 billion. Until projects can demonstrate 90% carbon capture, incorporating this requirement in the Rule is not realistic on a technical or financial basis.

10. The cost of transportation and storage for CCS is much higher in Montana's Powder River Basin than in other states. A study referenced in the proposed rule reports that the CO2 pipeline transportation and storage cost in 2018 was $22/tonne for the Powder River Basin. The other basins in the study were Illinois ($10/tonne), East Texas ($11/tonne), and Williston ($15/tonne). Montana questions the equity of its sites to have the same CCS requirements as other states, while taking on much greater costs, which are based on reservoir geology and thereby unavoidable.

11. EPA dismisses the potential impacts to electric system reliability caused by closure of EGUs that are unable to justify the economic impact of Rule compliance costs. In dismissing those concerns,

EPA does not adequately account for direct impacts of the Rule in Montana and the NorthWestern Energy Balancing Authority that would be caused by potential closure of impacted EGUs. Colstrip Units 3 and 4 generated forty one percent of the electricity generated in Montana in 2022, and represented twenty three percent of total installed generating capacity, see Electricity Statistics Tables, Mont. Department of Environmental Quality, accessed at https://deq.mt.gov/files/Energy/Documents/Energy_Statistics/ElectricityTables2023-Updated.xlsx. Colstrip's generating capacity in high load events varies depending on maintenance schedules, and the availability and price of other supply resources. However, during the peak of record setting electricity demand in the NorthWestern Balancing Authority driven by a severe cold weather event in January 2024, coal fired EGUs within the balancing authority generated seventy five percent of the customer electricity demand, see Hourly Electric Grid Monitor, U.S. Energy Information Administration, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/NWMT (accessed May 8, 2024). Peak electricity demand for that event hit on January 13, 2024, a day when temperatures dropped below minus 30 degrees Fahrenheit in major population centers served by NorthWestern.

12. If the costs of compliance with the Rule prove prohibitively expensive to undertake, the Rule requires retiring Colstrip Units 3 and 4 prior to January 1, 2032, leaving large industrial customers and utility owners of the units to replace the generating capacity and energy output of those EGUs with a mix of resources capable of reliably meeting comparable energy and capacity requirements, while continuing to meet the growing demand for electricity in Montana. The requirement to replace the output of the Colstrip units would come at a time when the Western Electricity Coordinating Council has assessed that, "(s)upply chain disruptions, increasing costs, production obstacles, and an overwhelmed interconnection queue threaten industry timelines to build new resources," see 2023 Western Assessment of Resource Adequacy, Western Electricity Coordinating Council (accessed May 8, 2024), https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf. The uncertainty of adding replacement generation to adequately meet growing demand threatens the ability of Montana utilities to meet customer demands in accordance

with other legal requirements, such as North American Electric Reliability Corporation ("NERC") Standards. See NERC, Reliability Standards (last visited May 3, 2024), https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx.

13. Risks to electricity system reliability, driven in part by retirement of dispatchable, high-capacity factor thermal EGUs, is a matter of significant concern. WECC reports that current utility resource plans in the western interconnect "are not sufficient to meet future demand over each of the next 10 years," and that "starting in 2026, the number and magnitude of demand-at-risk hours increase by orders of magnitude." WECC attributes the growing risks to reliability to increasing variability, "driven primarily by the addition of non-dispatchable variable energy resources (VER), the retirement of dispatchable resources, and the increase in load uncertainty due to extreme weather events," see 2023 Western Assessment of Resource Adequacy, Western Electricity Coordinating Council (accessed May 8, 2024),
https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

Sonja Nowakowski

SONJA NOWAKOWSKI
Dated: May 10, 2024

EXHIBIT 14

DECLARATION OF GAVIN MCCOLLAM

I, Gavin A. McCollam, declare as follows:

1. My name is Gavin A. McCollam. I am the Senior Vice President and Chief Operating Officer of Basin Electric Power Cooperative ("Basin Electric"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called upon and sworn as a witness, could and would competently testify to them.

2. I have more than 35 years of experience in the electric generation industry. I have been employed at Basin Electric since 1989. I hold an associate's degree from Bismarck (North Dakota) State College, a bachelor's degree in mechanical engineering from North Dakota State University, and a master's degree in systems management from the University of Southern California. I am also a registered professional engineer.

3. Basin Electric is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of NRECA's and North Dakota's legal challenges to the rule entitled

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, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

I. BASIN ELECTRIC

4. I am familiar with how the Final Rule will affect Basin Electric, the electric markets, and suppliers of electric equipment and services, as well as Basin Electric's consumer members.

5. Basin Electric is a not-for-profit generation and transmission ("G&T") cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives. Those member cooperatives—140 of them—are Basin Electric's owners. Through them, Basin Electric serves approximately three million consumer members in an area that covers roughly 500,000 square miles across nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Basin Electric's end-use consumer members across these nine

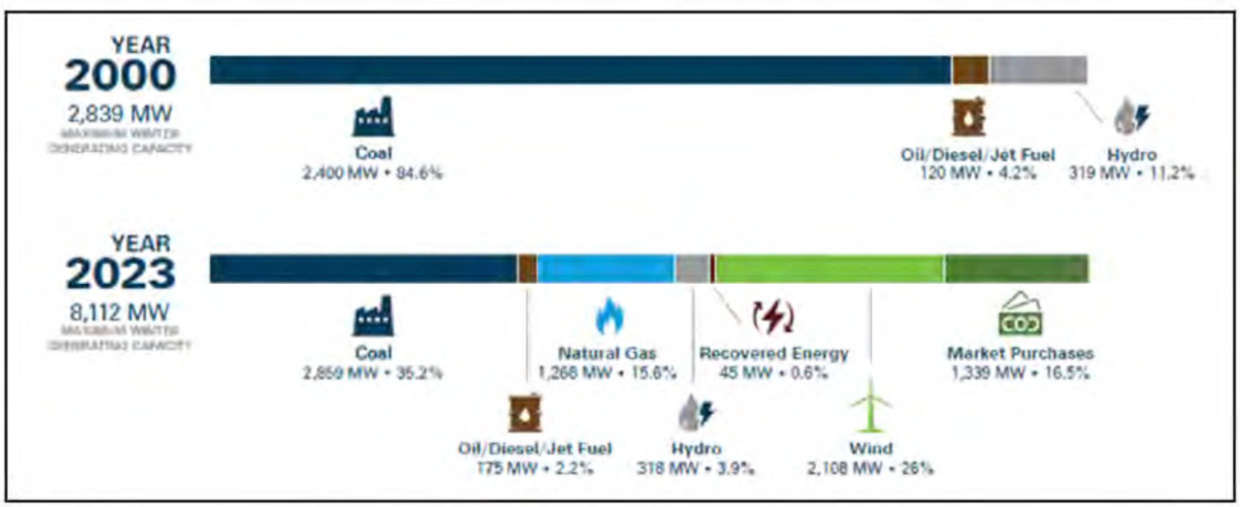
states include residential, farm, commercial, industrial, and irrigation electric consumers. In 2022, Basin Electric's farm and residential consumer members accounted for 29% of its megawatt-hour ("MWh") sales, while the commercial and industrial consumer members accounted for 68% of the MWh sales.

6. As of the end of 2023, Basin Electric had an asset base of $8 billion and operated 5,219 megawatts ("MW") of wholesale electric generating capability and had 8,112 MW of generating capacity within its portfolio. Those owned electric generation facilities are located in the states of Iowa, Montana, North Dakota, South Dakota, and Wyoming. Basin Electric's members provide electric service to 75% of the persistent poverty counties located within the nine states served, according to the 2023 persistent poverty data compiled by the U.S. Department of Agriculture Economic Research Service.

7. In order to provide the reliable electric supply that the member owners expect, Basin Electric is committed to an "all of the above" generating strategy which calls for multiple generating units utilizing

diverse fuel types (both fuel-fired and renewable resources) at dispersed locations. Basin Electric has invested and committed to approximately $7 billion dollars in developing new renewable energy resources, and it currently has a renewable energy portfolio of approximately 2,100 MW (as of the end of 2023). The other components of Basin Electric's portfolio include coal-fired generation (≈2,850 MW), natural gas-fired generation (≈1,250 MW), market purchases (≈1,350 MW), hydroelectric (≈300 MW), other fossil fuels (≈175 MW), and recovered energy (≈50 MW).

8. Basin Electric's diverse portfolio of electricity generation is a result of the significant investments that Basin Electric has made in the past two decades, as the following infographic summarizes:



9. Basin Electric has many electric generating units ("EGUs") that fall within the scope of the Final Rule ("affected EGUs") and thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that would be significantly shortened under the Final Rule absent massive amounts of new investment to cover all the compliance costs that the Rule creates. These substantial costs would fall on Basin Electric, and ultimately, on our rural consumer members. The table below identifies the EGUs that would be impacted if the Final Rule takes effect. The table also shows the results of Basin Electric's preliminary analysis of the approximate capital costs to comply with the Final Rule.

Affected EGU	**State**	**Compliance Strategy**	**≈ Capital Cost**
Dry Fork Station	WY	Long Term: CCS at 90%.	$2 billion
Antelope Valley Station Unit 1	ND	Medium Term: Co-fire with natural gas by 2029; retire by 2038.	$104 million
Antelope Valley Station Unit 2	ND	Medium Term: Co-fire with natural gas by 2029; retire by 2038.	$104 million

Leland Olds Station Unit 1	ND	Applicability exemption; retire by 2031.	$0
Leland Olds Station Unit 2	ND	Applicability exemption; retire by 2031.	$0
Laramie River Station Unit 1*	WY	Unknown	Unknown
Laramie River Station Unit 2*	WY	Unknown	Unknown
Laramie River Station Unit 3*	WY	Unknown	Unknown
Walter Scott Jr. Energy Center Unit 3**	IA	Unknown	Unknown
Walter Scott Jr. Energy Center Unit 4**	IA	Unknown	Unknown
George Neal South Generating Station Unit 4***	IA	Unknown	Unknown
Replacement Generation		Unknown	Unknown

*Basin Electric owns an undivided joint interest in Laramie River of approximately 42%.

** Basin Electric has a power purchase agreement with one of its members for the output of their ownership interest in Walter Scott Jr. Energy Center Unit 3 and Unit 4. Through those agreements with its members, Basin Electric has financial responsibility for approximately 4% of Unit 3 and approximately 6% of Unit 4. Such rights do not provide the ability to make decisions on these Units.

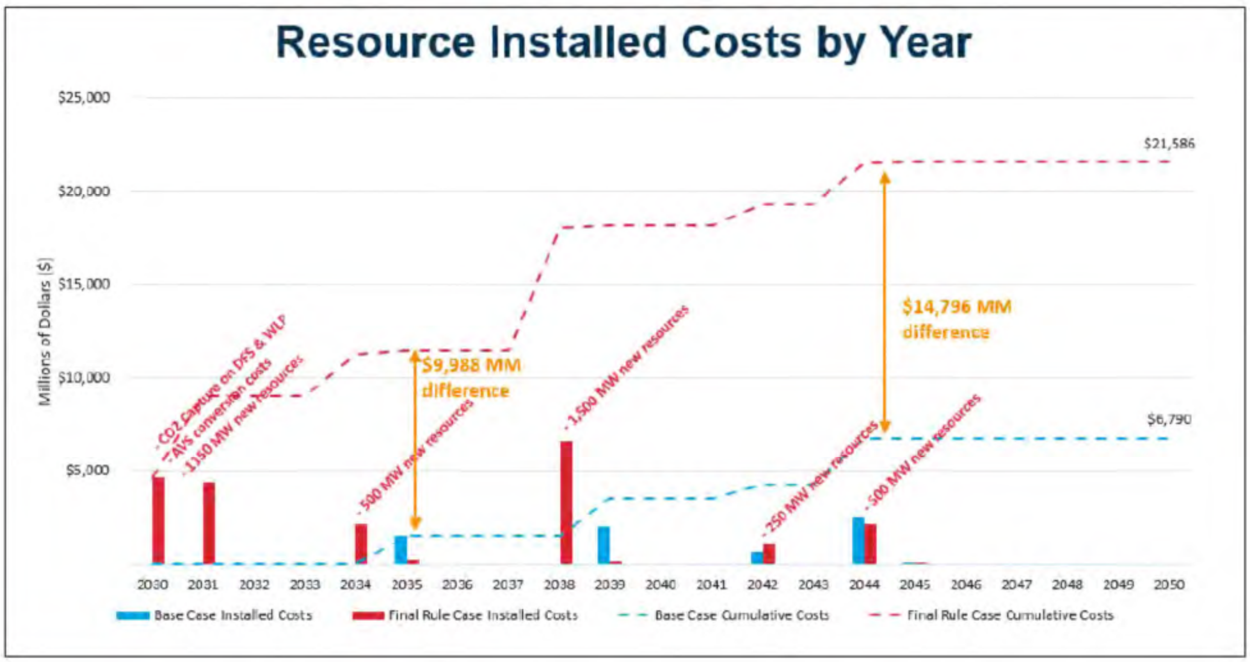
*** Basin Electric has two power purchase agreements with two of its members for the output of their ownership interest in George Neal South Unit 4. Collectively, Basin Electric has financial responsibility for approximately 16% of the unit. This percentage does not provide the ability to make decisions on this unit. MidAmerican Energy Company, as the majority owner and the operator of the unit, has this right and responsibility.

10. Basin Electric is currently in the middle of a massive generation and transmission buildout necessary to address load growth and long-term grid stability for its growing membership. Basin Electric is constructing an addition of approximately 580 MW of natural gas simple cycle generation to the existing Pioneer Generation Station, at a cost of approximately $800 million, that is expected to come online in 2025. Basin Electric is also actively investigating the need for more than 1,000 MW of dispatchable generation in western North Dakota by 2030 to address members' needs. This new generation will also need to comply with the Final Rule. In addition to these active generation projects, Basin Electric is also constructing over 300 miles of high voltage transmission line projects along with several major substation projects. The transmission line projects include the Roundup-to-Kummer Ridge 345kV project, the Leland Olds Station-to-Tande 345kV

project, and the Tande and Wheelock-to-Saskatchewan 230kV project. These projects have a combined cost of more than $700 million.

11. The table and graph below illustrate the projected capital cost associated with the planned generation expansion without the Final Rule ("Base Case"), as well as the projected capital cost associated with meeting load growth and complying with the Final Rule through 2045 ("Final Rule Case"). The incremental capital cost through 2035 to comply with the Final Rule is nearly $10 billion. **The incremental capital cost through 2045 to comply with the Final Rule is more than $14 billion.** These costs do not include any costs that would be associated with Final Rule compliance at Laramie River, Water Scott Jr. Energy Center, or George Neal South Generating Station.

2030-2045	Base Case	Final Rule
Total Need (SPP):	3,000 MW	3,500 MW
Total Need (RMPA):	350 MW	450 MW
Total Need (MISO):	45 MW	45 MW
Total Resource Need:	3,395 MW	3,995 MW
Avg Resource Costs:	@ ~$2,000/kW	@ ~$4,400/kW
Total Cap Costs:	$6,790,000,000	$17,578,000,000
Net Incremental Costs to Resource Expansion		+$10,788,000,000
NG Conversion		+$ 208,000,000 +
Carbon Capture on DFS + WLP Resource		+$ 3,800,000,000
Total Incremental Costs		**=$14,796,000,000+**



II. OVERVIEW OF THE FINAL RULE

12. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam electric generating units, under Section 111(d).

89 Fed. Reg. 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* 39902. Both types of units must meet emissions limits equal to what EPA believes 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically limit their output of electricity.

13. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* For purposes of implementing these subcategorizations for a particular unit, EPA recognizes only those retirement commitments that are made "federally enforceable" via inclusion in a State plan. *Id.* 40000. State plans are due to EPA in 24 months. *Id.* 39997.

14. The first (and default) subcategory is for "long-term" units, which EPA defines as units that "intend to operate past January 1, 2039." *Id.* 39801. EPA says that the best system for this subcategory is CCS that

captures 90% of the CO_2 from a unit. *Id.* 39845. This system begins with the design, engineering, and installation of CO_2 capture technology. *Id.* 39846. Then the captured CO_2 must be transported (usually via pipeline) to a site that can permanently sequester it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in "June 2024." *Id.* 39874. And the Rule requires unit operators to complete that work before January 1, 2032. *Id.* 39801.

15. The second subcategory is for "medium term" units: those that commit "to permanently cease operations" sometime "after December 31, 2031" but "before January 1, 2039." *Id.* 39841; *see id.* 39958. EPA says that best system for this subcategory is "[n]atural gas co-firing at 40 percent." *Id.* 39801. That means transforming a coal unit into a unit that combusts both coal and natural gas. *See id.* Just "[a]s in the timeline for CCS," EPA "assumes" that "work" toward co-firing will begin in June 2024. *Id.* 39893. And the Rule requires medium-term unit operators to complete that work before January 1, 2030. *Id.* 39845.

16. Third, the Rule establishes an "applicability exemption" for units that commit "to permanently cease operation before January 1, 2032." *Id.* 39841. These units "are not regulated by" the Rule. *Id.* 39843. However, if such a unit then "continues to operate past [that date], then it is no longer exempt," *id.*, putting the unit "in violation of" the State plan and the Clean Air Act, *id*. 39991.

17. *New gas-fired combustion turbine units*. For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* 39908. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* 39917. "Intermediate load" units (those that sell 20-40%) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units (those sell more than 40%) must comply with a "multi-phase standard of performance." *Id.* 39923. Phase I is "based on the performance of a highly efficient combined cycle turbine" and has "an

immediate compliance date." *Id.* 39903. Phase II is based on 90% CCS and has "a compliance date of January 1, 2032." *Id.*

III. IMPACTS TO AFFECTED EGUs

18. *Impacts at Dry Fork Station — "Long Term" subcategory.* The Dry Fork Station ("Dry Fork") consists of one 405 MW affected EGU located in Gillette, Wyoming. It began operation in 2011, with a construction cost of $1.35 billion. The station uses pulverized subbituminous coal technology and the latest generation of pollution control technologies resulting in very low emissions. As water is a scarce resource in Wyoming, Dry Fork uses air cooling. The plant location has potential area to site a carbon capture unit. Dry Fork is home to the Wyoming Integrated Test Center and the Wyoming CarbonSAFE project, both of which receive funding from the Department of Energy and the state of Wyoming for research projects that aim to help develop CCS technology.

19. Dry Fork is a relatively new coal-fired power plant, and its remaining depreciable life extends into the early 2070s. As a result, Basin Electric plans to leave Dry Fork within the Final Rule's default category for

"long term" EGUs. That decision requires Basin Electric to achieve 90% CCS at Dry Fork by the end of 2031. That level of CCS, if it can be achieved at all and in that time frame, can only be achieved with significant time and at great expense and risk. Indeed, Basin Electric is not aware of any manufacturer currently offering to warrant equipment that will achieve 90% CCS under *any* conditions, much less under large-scale and high-demand baseload conditions. Still, to have any hope of meeting the Final Rule's 2031 deadline for Dry Fork, Basin Electric must immediately begin spending money across a variety of expense categories.

20. *Carbon capture costs.* If it is possible to achieve 90% carbon capture at Dry Fork, it would require the addition of a post-combustion capture system. The cost for such a system is estimated to total approximately **$2 billion**. That astronomical expenditure is more than 150% of what it cost to construct the Dry Fork in the first place barely a decade ago. Complying with the Final Rule's 2031 deadline would require that Basin Electric enter into engineering, equipment, and other contracts immediately.

21. Basin Electric would first need to enter into engineering contracts, as a great deal of engineering would need to be performed prior to entering into any equipment contracts. Engineering costs typically represent approximately five percent of project costs, and are typically more costly for projects which involve the construction of new technology. In addition, Basin Electric would also need to hire an engineering firm to commence modeling work in order to apply for the permits necessary to begin construction of such a project.

22. The next step is ordering equipment. The carbon capture process equipment alone would cost Basin Electric approximately $400 million and a down payment of approximately 10% would likely be required. Engineering and equipment would need to be scheduled and committed to within the next 12 months. Based on previous experience, approximately 5 – 10% of the total project cost is spent on engineering and design costs. In the first two years alone, Basin Electric would expect to spend approximately $20 million on preliminary engineering and design costs that, but for the Final Rule, would not be expended.

23. *Carbon transport costs.* For CCS to work, once captured, the CO_2 must be transported to appropriate pore space. At Dry Fork, this would require approximately 27 miles of pipeline, based on preliminary studies. Some level of CCS would be feasible at Dry Fork (if at all) only because there is pore space in the region that could accommodate CO_2 storage. Still, constructing a pipeline to transport captured CO_2 from Dry Fork to this location would cost approximately $4 million per mile. Given high demand and long lead times for labor and specialized piping—both of which will only worsen as owners of EGUs across the country simultaneously attempt to comply with the Final Rule—Basin Electric must begin spending money immediately for planning, design, engineering, siting, permitting, and construction of a pipeline to transport captured CO_2.

24. Basin Electric's subsidiary, the Dakota Gasification Company, recently built a CO_2 pipeline. Based on that project, we estimate the required pipeline for Dry Fork would cost approximately $108 million and that Basin Electric would perform the engineering design and procure the equipment at a cost of approximately $50 million in the first two years.

25. *Carbon storage costs*. Once it is transported, the captured CO_2 from Dry Fork must be stored. Identifying and contracting for the necessary pore space is likely as challenging as meeting the 90% carbon capture requirement. Pore space in Wyoming will be challenging to procure, in light of the large percentage of federally owned land within the state. There is potentially suitable geology for CCS near Dry Fork, but geology is only the first piece of the puzzle. Even once transportation is solved, pore space can be utilized for storage only after an operator leases the thousands of acres of pore space and designs, permits, and constructs the storage facility. As with constructing a pipeline, all of that is outside Basin Electric's control. Leasing pore space for storage is both time-consuming and expensive.

26. *Operational costs*. According to a third-party study that Basin Electric commissioned several years ago, the annual operating and maintenance cost for 70% carbon capture at Dry Fork was estimated to be $56 million (2029). But even implementing that plan would not be sufficient to comply with the Final Rule, which would instead require Dry Fork to achieve a 90% CCS by January 1, 2032. Assuming 90% capture could be

achieved, that level of CCS would cost even more in annual operating expenses. The technology for attempting to achieve 90% CCS also demands significant water usage. Water is a scarce resource in Wyoming and would only be available at substantial expense. All of these are costs that Basin Electric must ultimately pass through to its consumer members.

27. *Reliability impacts*. One further significant cost is that CCS at any level tends to make an EGU less reliable. This makes unplanned outages more frequent and more severe. Basin Electric personnel have been to the Boundary Dam CCS project in Saskatchewan, and Basin Electric is familiar with the challenges experienced by SaskPower in maintaining and operating that capture unit, including unplanned outages. Unplanned outages increase Basin Electric's overall costs, hurt its relationships with consumer members, and can even affect its standing with the Regional Transmission Organization ("RTO"). Therefore, the reliability impacts of CCS are another significant risk facing Basin Electric.

28. *Impacts at Antelope Valley Station — "Medium Term" subcategory.* The Antelope Valley Station ("Antelope Valley") consists of two affected

EGUs located in Beulah, North Dakota. Each EGU is rated at 450 MW. Antelope Valley is located on a site adjacent to Dakota Gasification Company's Great Plains Synfuels Plant. Antelope Valley began operation in the 1980s, with a construction cost of approximately $1.9 billion. Antelope Valley is fueled by lignite coal from the adjacent Freedom Mine.

29. Antelope Valley's remaining depreciable life extends into the 2040s. Yet the Final Rule's default BSER—90% CCS by the end of 2031—is not economically feasible at Antelope Valley due to the age of the units and the short time that would be available to recover the massive investment necessary for CCS. Basin Electric has engaged in extensive efforts to participate in CCS research and development, including spending millions of dollars toward project development to build a demonstration project at Antelope Valley. That demonstration aimed to capture CO_2 emissions from about *one quarter* of *one* of the units at the plant. In other words, even this state-of-the-art demonstration project would not be sufficient to comply with the Final Rule. But even with a $100 million grant from the DOE and the availability of Dakota Gasification Company's pipeline for transporting the

captured CO_2, Basin Electric's feasibility study determined that the technology required too large of a parasitic load. Additionally, it came with an estimated cost of at least $500 million in 2010, would result in a significant increase in the cost of electricity to Basin Electric's members, and posed too great a risk given the technology provider was unwilling to guarantee the removal rate.

30. Due to these and other factors, Basin Electric plans to subcategorize Antelope Valley into the Final Rule's "medium term" subcategory. That election requires Basin Electric to make a legally binding commitment (in 2025 or 2026) to shut Antelope Valley down by 2038, and to achieve 40% natural gas co-firing at Antelope Valley by the end of 2029. To achieve that, Basin Electric must immediately begin spending money across a variety of expense categories.

31. *Equipment costs*. Retrofitting Antelope Valley's EGUs to co-fire 40% natural gas by the end of 2029 will require Basin Electric to make immediate capital expenditures. Antelope Valley uses natural gas as a startup fuel, but the existing equipment only allows for approximately 20%

co-firing. Because of that, each EGU's burner unit must be replaced, at an approximate total cost of $4 to 5 million. Burners are not "off the shelf" equipment, but instead must be purchased from a limited number of original equipment manufacturers, all of whom will simultaneously be facing a massive increase in demand from other affected EGUs across the country.

32. *Transport costs*. Basin Electric cannot co-fire natural gas at Antelope Valley unless there is a way for natural gas to be transported to those EGUs. Antelope Valley currently receives natural gas for startup fuel via a pipeline sourced from the Great Plains Synfuels Plant. However, to have an independent supply of natural gas would require installation of an approximately 40-mile pipeline connecting Antelope Valley to the closest interstate gas pipeline, Northern Border Pipeline, and related fuel supply infrastructure at cost of approximately $160 million (based on the assumption of $4 million per mile.) Given the long lead times for construction projects, a pipeline operator must begin design, permitting, siting, procurement, and construction immediately merely to have a chance to have natural gas available to Antelope Valley in time for the Final Rule's

end-of-2029 deadline. But no operator is likely to take all those steps without a substantial, up-front commitment from Basin Electric—either in the form of a capital contribution to the project, or in the form of a long-term (20-30 year) supply contract. Even if Basin Electric identified an operator and agreed to such terms, there is no guarantee that such a pipeline could actually be completed in time. Permitting, engineering construction, right-of-way acquisition, and myriad other factors could block the pipeline or could delay it beyond the Final Rule's compliance deadlines. If that happened, Basin Electric's investments in equipment costs would be completely lost, and Antelope Valley would need to shut down.

33. *Permitting risks*. Converting Antelope Valley to natural gas co-firing will also require Basin Electric to obtain new permits, including a New Source Review permit and an updated Title V permit. But these permits are expensive and time consuming, and their issuance is also subject to judicial review. In order to have proper permitting in place by 2030, Basin Electric must immediately begin the permitting process for Antelope Valley.

34. *Impacts at Leland Olds Station – Retirement under Applicability Exemption.* The Leland Olds Station ("Leland Olds") consists of two affected EGUs that together generate 660 MW in Stanton, North Dakota. Unit 1 was placed into service in 1966 and Unit 2 was placed into service in 1975. Leland Olds uses lignite coal delivered via rail from the Freedom Mine near Beulah, North Dakota. The remaining depreciable lives of the two Leland Olds units extend to 2030 and 2040, respectively.

35. The default compliance path—90% CCS by the end of 2031—is not economically feasible at Leland Olds given the age of these units and the short time that would be available to recover the massive investment necessary for CCS.

36. The medium-term compliance path—40% natural gas co-firing by 2030, and closure by 2040—also is not economically feasible at Leland Olds, given the age of the units and the cost to bring natural gas to Leland Olds. To connect to the closest interstate pipeline, the Northern Border Pipeline, would require the construction of an approximately 50-mile pipeline. Connecting Leland Olds to that pipeline would be prohibitively

expensive. And given the current regulatory environment, it is also highly unlikely that such a connection could be designed, sited, permitted, constructed and right-of-way acquired before the Final Rule's 2030 deadline. Furthermore, even with a firm supply of natural gas, co-firing natural gas at Leland Olds would require substantial investments in new equipment.

37. Because of those and other factors, Basin Electric has no choice but to commit (in 2025 or 2026) to retire Leland Olds by the end of 2031 to claim an applicability exemption under the Final Rule. That election requires Basin Electric to make a legally binding commitment to shut down Leland Olds by the end of 2031. This compliance pathway requires Basin Electric to immediately begin incurring expenses across a variety of expense categories.

38. *Transmission costs*. Whereas Leland Olds sits at a single site, replacement generation units would need to be dispersed over a broad area. That said, prior to doing any transmission planning, Basin Electric would first need to do the engineering studies to determine where it will place the generating units to replace the lost capacity from Leland Olds. This reality will require Basin Electric to make immediate and substantial investments

in these studies before it can even begin to plan for new transmission. A reasonable estimate of the cost of additional transmission lines is approximately $2 million per mile.

39. *Coal supply costs*. Basin Electric purchases coal for Leland Olds from the Freedom Mine (which also provides lignite coal to Basin Electric's Antelope Valley), and also from the Dakota Gasification Company's Great Plains Synfuels Plant. But if Leland Olds shuts down at the end of 2031, the cost of coal to Antelope Valley would increase significantly. That is because a substantial portion of the costs of mining are fixed costs. Losing a major purchaser in the next decade would result in the pass through of these fixed costs over a smaller number of tons. The mine will pass these costs on to Basin Electric in the form of higher prices for coal, and those increased costs will ultimately fall on Basin Electric's consumer-members.

40. *Impacts at Laramie River Station.* Basin Electric is a minority co-owner of the Laramie River Station ("Laramie River") located in Wheatland, Wyoming. Laramie River's three affected EGUs generate approximately

1,700 MW, of which Basin Electric owns about 42%, for a total of roughly 714 MW. Basin Electric is also the operator of Laramie River.

41. Decisions about compliance for Laramie River are not solely Basin Electric's to make. Instead, decisions are made by a majority of the station's owners. Decision-making about the compliance plan for Laramie River is still in process. Even so, and for many of the same reasons discussed above (and below) with regard to the other EGUs in Basin Electric's portfolio, each of the available compliance pathways under the Final Rule would require Basin Electric to immediately begin incurring substantial expenses—either in the form of new equipment (*e.g.*, CCS, natural gas supply, or co-firing equipment), replacement generation (if Laramie River retires by 2031), or both. If the owners of Laramie River chose to subcategorize the units into the medium-term subcategory, retrofitting the Laramie River EGUs to co-fire with natural gas would cost approximately the same as for each unit of Antelope Valley.

42. *Iowa Plants.* Basin Electric has entered into power purchase agreements with two of its members to purchase the output of capacity and

energy from their ownership interest in three coal-fired generating units in Iowa. Those three coal-fired generating units include George Neal South Generating Station South Unit 4 (Neal 4), Walter Scott Jr. Energy Center Unit 3 (Walter Scott 3), and Walter Scott Jr. Energy Center Unit 4 (Walter Scott 4), located near Sioux City, Iowa—all of which are operated by MidAmerican Energy Company. The power purchase agreements that Basin Electric has with its members provide Basin Electric with the responsibility to reimburse its members for approximately 16% of the costs of the unit. The remaining depreciable life of Neal 4 extends to 2040.

43. The Walter Scott units 3 and 4 are in Council Bluffs, Iowa. The power purchase agreement that Basin Electric has with its member provides Basin Electric with the responsibility to reimburse its member for approximately 4% of Walter Scott 3 and 6% of Walter Scott 4. The remaining depreciable lives of Walter Scott 3 and 4 extend to the late 2030s and 2060s, respectively.

44. Since Basin Electric's members do not own the entire units and their ownership interests are relatively small, they do not have the ability to

make the decision on the compliance strategy that these units would pursue. Each of these units is operated by MidAmerican Energy Company, which also has the largest ownership interest in each unit. Depending on the compliance strategy that would be selected for each of the units, there is the possibility that Basin Electric may have to look for replacement power alternatives to replace any lost power due to compliance with the Final Rule.

IV. REPLACEMENT POWER

45. *Dry Fork*. Even if 90% CCS could be achieved at Dry Fork, actually running the technology requires substantial amounts of power. This dynamic creates what is referred to as a "parasitic load," that is, the CCS system drains or otherwise consumes a portion of the electrical energy generated by its host EGU. At Dry Fork, the **parasitic load for CCS is estimated to be about 25%** of the EGU's total capacity. This means that about 100 MW out of Dry Fork's 405 MW of capacity would be redirected from Basin Electric's members in order to support CCS at Dry Fork. As a result, Basin Electric must replace that power in order to continue to meet

member demand. This will require either buying new power from the market or building 100 MW of new generation.

46. But if the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios. Thus, the most cost-efficient option to address the parasitic load of CCS is to build new generation to offset the 100 MW loss at Dry Fork. Yet the Final Rule also imposes stringent requirements for new base load gas-fired combustion turbine EGUs—all of which must achieve 90% CCS. That level of CCS is not possible for new EGUs, which would be composed of natural-gas units rather than coal-fired units. Nor can Basin Electric depend on renewables for baseload generation.

47. Thus, for new generation to offset the parasitic load of CCS at affected EGUs, Basin Electric's options include building (1) a large number of low-capacity combustion turbines ("CTs") all running at a capacity factor of 20% or less; (2) reciprocating internal combustion engines; or (3) combined cycle generation with its capacity factor limited by its efficiency. All three of these options are expensive and inefficient. As an example, to achieve 100

MW of reliable baseload generation, Basin Electric would need to build 600-700 MW worth of CTs (the extra MW being necessary to satisfy the applicable RTO reserve-margin requirements). For that generation to offset the 100 MW loss at Dry Fork to be available by 2030, Basin Electric must begin spending money now for engineering, planning, design, siting, permitting, fuel procurement, and construction.

48. *Leland Olds*. Retiring Leland Olds by 2031 would reduce the energy available from Leland Olds to provide energy to Basin Electric's consumer members. In aggregate, this retirement reduces Basin Electric's resource portfolio by 660 MW. Basin Electric would need to replace the lost energy from the units. Basin Electric must replace that capacity to ensure that its members receive reliable and affordable electric service.

49. Basin Electric cannot turn to the market for that amount of generation. Instead, it must construct new generation. Conservatively, replacing that level of generation will cost approximately $3 billion (based on an assumed cost of $4,400 per kW). All of these costs will be exacerbated by the fact that the Final Rule does not allow for new baseload EGUs unless

they can achieve 90% CCS, which has not been demonstrated. To ensure that adequate new generation is available by the time Leland Olds is forced to shut down completely at the end of 2031, Basin Electric must begin making capital expenditures now.

50. *Laramie River and Iowa Units.* Depending on the election taken by the owners of Laramie River, Basin Electric would be looking at replacing 714 MW of its entitlement at Laramie River in either 2031 or 2038. Similarly, depending on how the owners of the units in Iowa choose to comply, Basin Electric would need to replace 200 to 210 MW in either 2031 or 2038.

V. CUMULATIVE IMPACT OF THE FINAL RULE ON BASIN ELECTRIC

51. Basin Electric operates the largest G&T cooperative fleet of affected EGUs, relies on that fleet to produce the highest amount of MWs, and distributes that energy across the largest G&T footprint in the Nation. Meanwhile, Basin Electric's current load forecast projects that Basin Electric's load is expected to grow at more than 4% annually over the next ten years, which amounts to an increase of more than 2,000 MW during this decade. This significant load growth is due to a combination of residential,

agricultural, commercial, and industrial development, including facilities to be constructed with funding and tax incentives under the Inflation Reduction Act. The Final Rule has an inordinate impact on Basin Electric.

52. By 2035, complying with the Final Rule will require nearly $10 billion in incremental capital expenditures, nearly doubling Basin Electric's current asset base. Complying with the Final Rule will also increase the Operating & Maintenance expenditures where new systems and equipment are added. Those expenses will fall on members, who already expect to see rate increases associated with load growth. Additional expenses resulting from the Final Rule will result in a rate increase of approximately 60% for members by 2035. At the same time, the capital expenditures spent to comply with the Final Rule (in addition to previously planned capital expenditures for member load growth) will increase the amount and costs of Basin Electric's borrowing, and will negatively affect Basin Electric's capitalization and coverage ratios. Additionally, the rating agencies will likely view the substantial increase in debt, operational execution challenges of complying with the Final Rule, and significant reliance on unproven technology as

negative credit factors in their assessment of Basin Electric's credit. All these impacts would likely have a negative impact on Basin Electric's bond ratings, which would further compound the challenge of obtaining sufficient capital at a reasonable cost to comply with the Final Rule.

53. Basin Electric and other G&T cooperatives enter into long term "all requirements" contracts with their member-owners. Basin Electric's "all requirements" contracts require Basin Electric to meet all of the members' electricity demand for the duration of the agreements (which run through 2050 or 2075).

54. By forcing EGUs to retire early, the Final Rule seriously threatens Basin Electric's ability to meet its contractual commitments to supply "all requirements" to its members. Forced retirements will also make it more difficult for Basin Electric to satisfy the planning reserve margins that the RTO, Southwest Power Pool ("SPP"), and Midcontinent Independent System Operator ("MISO") require. These margins are the magnitude of incremental accredited capacity that Basin Electric must have available to meet unexpected increases in demand, or to cover for capacity that might be

unavailable due to maintenance or unexpected outages. In other words, the planning reserve margin is a percentage that represents the amount of available capacity over and above the expected peak demand. Forced retirement of baseload EGUs makes it more difficult for Basin Electric to comply with the RTOs' current planning reserve margins requirements. In addition, these planning reserve margins have also been increasing to offset the intermittency that is inherent in renewable resources such as wind and solar, which have greatly increased as a percentage of the RTO resource mix in the last decade. This is further exacerbated as renewables continue to grow and displace dispatchable generation facilities that have retired, will retire in the future, or could be limited in their operation in the future.

55. Thus, at the same time that planning reserve margin requirements and demand are steadily *increasing*, the Final Rule's forced EGU retirements are drastically *decreasing* the amount of available baseload dispatchable generation.

56. Systematic premature retirement of baseload EGUs increases the likelihood of blackouts and other reliability failures, like those experienced

in Texas during Winter Storm Uri in February 2021. Replacing the baseload power from EGUs is challenging, expensive, and time-consuming. Current supply-chain delays, the limited number of available suppliers, labor-market shortages, and the limited capacity of the capital markets will only worsen as utilities across the Nation simultaneously rush to construct replacement EGUs. In other words, the Final Rule causes significant short- and long-term harm to both Basin Electric and the electric utility industry as a whole.

VI. ABSENT A STAY, BASIN ELECTRIC WILL SUFFER IMMEDIATE IRREPARABLE HARM

57. Basin Electric has made significant expenditures for resource planning, technology evaluations, and CCS research and design studies. As a result of these studies, Basin Electric has put itself in a position to understand the cost, timing, and scope of the effort necessary to comply with the Final Rule.

58. An interconnection study is a meticulous process that can span several years, with recent requests taking up to 7 years to complete. Currently, the SPP generation interconnection queue contains over 400 active requests, some of which are over 6 years old without a final

Generation Interconnection Agreement. This delay prevents interconnection customers from knowing the total required interconnection costs necessary to make informed decisions about proceeding with the construction of generation.

59. Despite efforts by SPP and other RTOs to address the backlog of their interconnection queues, these numbers are expected to rise due to the influx of new requests prompted by the Final Rule. Consequently, Basin Electric must conduct studies to strategically plan the location of replacement generation and promptly submit interconnect requests to meet compliance deadlines. Even if utilities were able to promptly put in numerous interconnection requests, delays in the current interconnection processes would prevent utilities from making an informed, prudent decision to proceed. Accordingly, Basin Electric must first perform the studies necessary to plan the location of a large number of generating units and then act quickly to submit new interconnect requests in order to stand any chance of meeting the Final Rule's compliance deadlines.

60. At the same time that the Final Rule is forcing Basin Electric to rush to secure replacement power, RTO planning reserve margin requirements and the resource adequacy rules are changing to *increase* the amount of accredited capacity that Basin Electric must maintain as a market participant and load responsible entity. These requirements only pile on top of the other delays and expense factors previously discussed, and only increase the need for Basin Electric to take immediate action to comply with the Final Rule.

61. The National Environmental Policy Act ("NEPA") requires lengthy and highly detailed environmental reviews for projects that take place on federal land, receive federal funding, or require federal permitting or other approvals. Depending on the significance of the potential environmental impacts involved, an environmental impact statement or environmental assessment may be required. A federal agency's NEPA compliance is also subject to judicial review. Nearly half of Wyoming sits on federal land. This fact alone adds (at minimum) several years to many of the new Wyoming construction projects discussed above—whether siting for

replacement generation, transmission lines, pipelines to transport carbon, or pore space to store carbon in the state of Wyoming. The Final Rule requires Basin Electric to construct or rely on the construction of multiple new projects at or around multiple affected EGUs which may require compliance with NEPA. NEPA reviews (and potential related litigation) can literally add years to the construction process for these projects, and must be completed before work on a project may proceed. This only increases the need for Basin Electric to take immediate action.

62. *Section 106 delays*. Compliance with Section 106 of the National Historic Preservation Act—accounting for effects on historic properties—is also required for any projects that are carried out with federal financial assistance or requiring a federal permit, license, or approval. In other words, any project that triggers NEPA is also likely to trigger Section 106 review. Yet Section 106 determinations are also subject to judicial review, which can be lengthy and expensive, further illustrating the need for Basin Electric to take immediate action.

63. *Immediate engineering costs*. Attempting 90% CCS (at Dry Fork) by 2031 and 40% natural gas co-firing (at Antelope Valley) by 2029 would require Basin Electric to immediately begin with engineering studies, design studies, modeling studies, and permitting activities. All of that must happen soon, because each increment of delay puts compliance with the Final Rule even further out of reach. Multi-year engineering work would need to be performed prior to ordering any equipment. Equipment deliveries would likely follow placement of the orders by several years. Once the equipment is purchased and received, it must be installed and tested as part of the overall construction of the project. Then Basin Electric must troubleshoot to ensure that the equipment is operating efficiently and reliably.

64. Working backwards from the Final Rule's compliance dates, the engineering **should have already begun**. Indeed, when Basin Electric executed a Selective Catalytic Reduction ("SCR") project for Laramie River, the overall process took five years—and that was for a mature technology that is orders of magnitude simpler than CCS or conversion to co-firing, and that did not require new pipelines or underground storage.

65. Pipeline transportation is necessary for both CCS (CO_2) and co-firing (natural gas). Again, engineering studies and pipeline routing need to be undertaken immediately. Pipelines require state and federal permits. Landowner fatigue, increasing community resistance to pipelines, and difficulties in securing pore space for CO_2 storage and right-of-way for CO_2 pipelines have the potential to add significant time and cost to these new construction projects. And because these projects will require obtaining permits for novel components Basin Electric has not previously attempted (*e.g.*, pore space, transport for CO_2), projections must build in extra time. Basin Electric must immediately begin making expenditures in order to help bring these resources into existence in time for the Final Rule's compliance deadlines.

66. *Replacement power costs*. Basin Electric will need to **replace approximately 2,600 MW of baseload**, dispatchable generation significantly earlier than planned as a result of the Final Rule. Renewable energy sources (such as wind and solar) cannot satisfy that demand. Land acquisitions alone would be cost-prohibitive. But even ignoring that, renewables are an

intermittent resource that are available only *some* of the time. Thus, for replacement power, Basin Electric must turn to natural gas. But even today's state-of-the-art natural gas combined cycle units ("NGCCs") cannot achieve the 90% CCS that the Final Rule demands. Even if those units could achieve 90% CCS, constructing them would cost approximately **$11.4 billion** as compared to Basin Electric's current asset base of $8 billion**.** That estimate does not include land, water rights, financing fees, escalation, tax, or insurance. This estimate also does not include the significant costs for new transmission buildout and fuel transportation that would be associated with new units. In order to bring that amount of generation into its portfolio by the Final Rule's deadlines, Basin Electric has no time to spare. Instead, it must immediately begin the engineering work to construct replacement generation—whether NGCCs, CTs, renewables, or some combination thereof.

67. Even if Basin Electric could secure the vast amount of replacement power that is required due to the Final Rule's forced retirements and other requirements, that power is useless unless it can be effectively

transmitted to members. But much of the replacement power that Basin Electric must build will be in the form of distributed generation. For a variety of reasons—including cost, efficiency, and decommissioning work—these types of natural gas generation facilities would need to be sited at new locations near interstate natural gas pipelines and high voltage transmission lines (not at the old locations of the coal-fired EGUs that the Final Rule forces to retire). Because of that, Basin Electric will also need to immediately begin to determine the locations of new generation so that generation interconnection requests can be submitted to the RTOs.

68. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of NRECA's Petition for Review. Basin Electric expects that process to take *at least* 2 to 3 years. But the Final Rule's compliance deadlines do not give Basin Electric any time to spare. For one thing, the Final Rule's one-year compliance extension mechanism is available only if Basin Electric "has made all reasonable efforts to achieve timely compliance" and "has acted consistent with achieving timely compliance." 89 Fed. Reg. 607. In other words, Basin Electric must act

now in order to preserve its ability to claim the Final Rule's compliance extension mechanism (if it is even added to the State plans that will govern Basin Electric). For numerous other reasons, too, haste is of the essence.

69. Complying with the Final Rule will require Basin Electric to hire numerous consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required under the Final Rule. Yet these markets too are subject to the laws of supply and demand. As EGU owners across the Nation rush to hire the same professionals, availability will decrease, and prices will increase. Accordingly, EGU owners must move early—not only to insulate themselves from price pressures, but also in attempt to ensure that the needed professionals are even available.

70. Bringing replacement power online is a costly and time-consuming process. Initially, Basin Electric and other load-serving entities must submit an interconnection request to the appropriate RTO, such as SPP or MISO, depending on whose transmission facilities the generation facility will connect to. This request requires crucial details such as proposed

location, size, fuel type, prime mover description, intended commercial operation date, and point of interconnection specifications (substation name, line voltage), applicable study deposits, required financial security deposits, and evidence of site control or additional financial security. Once received, the RTO conducts an analysis to assess the impact of the new generation on the network. All of this takes large amounts of time and money.

71. *Immediate costs to Basin Electric.* All of the previously described costs are costs which Basin Electric would not incur but for the Final Rule. If Basin Electric begins incurring these costs as a result of the Final Rule and the Final Rule is ultimately overturned by the courts, these costs are sunk and cannot be recaptured. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded.

72. Without question, the greatest irreparable harm to Basin Electric and other members of the electric utility industry is the fact that we will be forced to make legally binding obligations to close power plants while the Final Rule is being litigated. Those kinds of retirement obligations would not otherwise arise for years or decades to come.

*   *   *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 10th day of May 2024, in Bismarck, ND.

Gavin A. McCollam

EXHIBIT 15

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF INDIANA, STATE OF ALABAMA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF FLORIDA, STATE OF GEORGIA, STATE OF IDAHO, STATE OF IOWA, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF NEW HAMPSHIRE, STATE OF NORTH DAKOTA, STATE OF OKLAHOMA, STATE OF SOUTH CAROLINA, STATE OF SOUTH DAKOTA, STATE OF TENNESSEE, STATE OF TEXAS, STATE OF UTAH, COMMONWEALTH OF VIRGINIA, AND STATE OF WYOMING, *Petitioners*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, Administrator, United States Environmental Protection Agency, *Respondents*.	Case No. 24-1120

DECLARATION OF JAMES L. SEMERAD
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, James L. Semerad, hereby declare and state under penalty of perjury that the following is true and correct to the best of my knowledge and is based on my personal knowledge or information provided by North Dakota Department of Environmental Quality (NDDEQ) personnel:

1. My name is James L. Semerad, and my business address is 4201 Normandy Street, Bismarck, ND 58503. I am over the age of 18, have personal knowledge of the subject matter, and am competent to testify concerning the matters in this declaration.

2. I have served as the NDDEQ Division of Air Quality Director since April 2019. I have a bachelors of science degree in civil engineering from North Dakota State University. As Director of the Air Quality Division, my responsibilities include overseeing North Dakota's air quality program, the purpose of which is to protect human health and the environment by maintaining air quality standards, limiting harmful emissions, and providing transparent information to the public about air quality conditions.

3. I am submitting this declaration in support of Petitioners' Motion to Stay the Final Rule, published by the U.S. Environmental Protection Agency (EPA) on May 9, 2024 entitled "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," 89 Fed. Reg. 39,798 (Final Rule).

4. NDDEQ's mission and vision is to conserve and protect the quality of North Dakota's air, land, and water resources following science and the law. In cooperation with the general

public, industry, and government at all levels, NDDEQ implements protective programs and standards to help maintain and improve environmental quality in North Dakota.

5. NDDEQ is responsible for ensuring that the air in North Dakota meets public health, welfare, and environmental standards established under the federal Clean Air Act (CAA), including New Source Performance Standards for electric generated units promulgated by the EPA.

6. Any time and resources that NDDEQ is required to dedicate to implementing the Final Rule while the legal challenges against it progress will be time and resources that NDDEQ will have to divert from other parts of its mission to safeguard North Dakota's public health, welfare, and environment, including its precious air, land, and water resources. That work will need to begin immediately given the enormity of the task at hand in order to propose and secure approval of a state plan soon enough to make compliance with the Final Rule's deadlines theoretically, if not practically possible.

7. On August 8, 2023, the State of North Dakota submitted comments in response to the EPA's proposed rule on this regulatory docket (2023 North Dakota Comment Letter). I share the concerns raised in that comment letter. Some of these concerns are listed below.

8. First, EPA's approach to subcategorization in the Final Rule violates the terms of the CAA. The Final Rule subcategories are based on EPA's presumptive compliance requirements paired with established compliance dates or forced requirement dates, rather than physical characteristics, specifically "classes, types, and sizes within categories." Not only does this violate the provisions governing how EPA may derive what constitutes a "best system of emission reduction (BSER)," it imposes on NDDEQ the difficult and time-consuming task of modeling and standards development based on business and operational decisions made

by the regulated community, which may change throughout the process of developing and finalizing the state plans. In other words, in the process of drifting from its statutory role in deriving BSER, EPA has imposed an unreasonable resource burden on NDDEQ to implement the Final Rule's requirements without any resource support by the EPA.

9. Second, the Final Rule violates the cooperative federalism mandated by the CAA generally and even more particularly under Section 111(d) of the Act. EPA's BSER guidelines are designed under the CAA to provide broad national guidance; it is up to the States to take the lead in implementing these guidelines within each State, given the unique needs, characteristics, and priorities within the State. But the Final Rule does the opposite, establishing nationwide, mandatory emission limitations that eliminate the authority and flexibility granted to each State under the CAA. Specifically, under the CAA states are granted the exclusive authority when applying a standard of performance to any particular source to take into consideration among other factors "remaining useful life of the existing source" and it is not appropriate for EPA, as they have done here, to impose its own desired limitations on the states' consideration of these factors.

10. Third, the Final Rule would undermine and directly harm North Dakota's longstanding sovereign interests in and leadership in promoting the development and application of carbon capture and storage ("CCS"). North Dakota has been working to develop and deploy CCS within North Dakota in ways that allow the State to utilize its unique natural resources for the foreseeable future. EPA's Final Rule, by setting BSER on an unreasonable, nationwide basis, will destroy decades of research, development, current and future investment in CCS and its prospects by forcing North Dakota's commercial partners to prematurely abandon their projects.

11. The Final Rule directly impacts ten existing lignite-fired electric generating units in North Dakota as well as thousands of related facilities that depend on, provide services to, or are otherwise related to those electric generating units.

12. Under the Final Rule, NDDEQ must submit a state plan to the EPA in order to receive authority to implement the emission guidelines for greenhouse gas ("GHG") emissions from existing electric generating units. Under the Final Rule, NDDEQ has two years to submit a proposed plan to cover existing sources in the electric generation industry that implements the Final Rule's standards for GHG emissions. As discussed further below, the planning process would be a tremendous undertaking. But NDDEQ's regulatory role must begin immediately. Beginning November 12, 2024, all EGUs that plan to permanently cease operations must develop detailed wind-down plans, document and obtain approval for those plans, and submit initial and annual reports. 40 C.F.R. § 60.5876b. Although the burdens of retirement-specific planning and reporting do not commence until an owner has concluded they will need to retire, industry declarations make clear that those decisions must be made soon.

13. NDDEQ has already expended substantial resources to review the EPA's May 2023 Proposed Rule and the November 2023 Supplemental Notice and to coordinate with other affected agencies within the State of North Dakota to provide comments. NDDEQ has participated in many webinars, informational sessions, and informal communications related to the proposals. Since the Final Rule has been released, NDDEQ is preparing to expend significant additional resources for developing a state plan that would satisfy the proposed emissions guidelines for existing sources.

14. If the Final Rule is not stayed, North Dakota and NDDEQ will be required to immediately undertake efforts to implement and comply with the Final Rule, which will result in extensive costs and administrative burdens for North Dakota and NDDEQ, none of which will be recovered.

15. In the absence of a stay of the Final Rule, NDDEQ estimates that it will need to dedicate at least 4,000 hours of staff time to:

    a. interviewing and studying the unique site-specific technical and economic considerations for each of the ten existing electric generating units in the State of North Dakota, evaluating a range of technical and legal factors implicated by the rule and each set of site-specific considerations, including how to apply the concept of remaining useful life to the EPA's new standards;

    b. developing North Dakota's standards of performance while evaluating existing North Dakota law and regulations for overlap and inconsistencies;

    c. assessing potential grid impacts of all of the above and developing mitigation techniques, if practical; and

    d. submitting plans for EPA approval.

16. Complying with the requirements mandated on the State by the Final Rule will impose a significant burden on our resource-constrained budgets, and the EPA has not provided adequate funding to offset those additional costs. NDDEQ is already staff constrained, and the work to complete a new state plan will place significant demands on staff with needed experience.

17. In short, complying with the Final Rule will impose substantial costs and an administrative burden on North Dakota, and these costs have already started to accumulate and will

immediately begin to increase drastically since deployment of the Final Rule. Significant staff time and resources will be required to develop a state plan. This process puts a significant burden on NDDEQ's staff and limited resources, impeding NDDEQ's ability to perform its many other duties in service of North Dakotans. Every hour of state staff time and dollar of state resources expended on the activities described above cannot be reclaimed. Once those resources are expended they are gone, and NDDEQ will not be able to recoup from the federal government any funds that were spent trying to comply with another EPA regulatory scheme declared to be unlawful.

18. Staying the Final Rule will allow NDDEQ to continue using its limited resources to protect the health and welfare of North Dakota's people and its environment without irreparably diverting substantial time and resources on the development of a state plan based on a Final Rule that may be held unlawful or otherwise undergo significant revision due to this litigation.

I declare under penalty of perjury under the laws of North Dakota that the foregoing statements are true and correct to the best of my knowledge.

Executed in Burleigh County, North Dakota, on May 10, 2024.

James L. Semerad
Director
Division of Air Quality
N.D. Department of Environmental Quality

EXHIBIT 16

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF INDIANA, STATE OF ALABAMA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF FLORIDA, STATE OF GEORGIA, STATE OF IDAHO, STATE OF IOWA, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF NEW HAMPSHIRE, STATE OF NORTH DAKOTA, STATE OF OKLAHOMA, STATE OF SOUTH CAROLINA, STATE OF SOUTH DAKOTA, STATE OF TENNESSEE, STATE OF TEXAS, STATE OF UTAH, COMMONWEALTH OF VIRGINIA, AND STATE OF WYOMING, *Petitioners*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, Administrator, United States Environmental Protection Agency, *Respondents*.	Case No. 24-1120

DECLARATION OF LYNN HELMS
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, Lynn Helms, hereby declare and state under penalty of perjury that the following is true and correct to the best of my knowledge and is based on my personal knowledge or information provided by North Dakota Department of Mineral Resources ("NDDMR"):

1. My name is Lynn Helms, and my business address is Dept. of Mineral Resources, Oil and Gas Division, 1016 E Calgary Ave, Bismarck ND 58505. I am over the age of 18, have personal knowledge of the subject matter, and am competent to testify concerning the matters in this declaration.

2. I have served as the Director of the North Dakota Department of Mineral Resources since it was formed in July 2005. I previously served as a Director of the North Dakota Industrial Commission Oil and Gas Division from July 1998 through July 2005. I have a bachelor's of science degree in engineering from South Dakota School of Mines and Technology and a Masters Degree and PhD in Petroleum Engineering from the University of North Dakota . The Department of Mineral Resources reports to the North Dakota Industrial Commission and is responsible for overseeing the management and development of many of the State's natural resources, including oil and gas, coal, geothermal energy, and the underground storage of carbon dioxide. As Director of the Department of Mineral Resources, my responsibilities include overseeing North Dakota's regulatory programs that cover the oil and gas development, carbon storage, and coal exploration industries in a manner that will realize the greatest possible good from North Dakota's vital natural resources for the State and its residents.

3. I am submitting this declaration in support of Petitioners' Motion to Stay the Final Rule, published by the U.S. Environmental Protection Agency (EPA) on May 9, 2024, entitled "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," 89 Fed. Reg. 39,798 (Final Rule).

<u>North Dakota's Extensive Experience with Carbon Capture and Storage</u>

4. For nearly 20 years, North Dakota has been at the forefront of actively supporting the development of Carbon Capture and Storage technologies (CCS). This is due in part to geologic conditions in North Dakota that make implementing CCS particularly viable within the state. And NDDMR is the State agency responsible for overseeing North Dakota's development and implementation of CCS.

5. North Dakota was the first state in the country to pursue and receive authorization from the EPA to permit CCS projects. To date, North Dakota has approved six CCS storage facilities for operation or construction. The technology for safe long term geologic storage of CO2 is well understood and has been operating at scale for lignite gasification and ethanol production for many years, and North Dakota remains optimistic that CCS will one day be capable of being implemented at a large scale for electric generating units. Although CCS is being deployed for ethanol and lignite gasification production, CCS for large scale electric generation is not yet at the stage where it can be deployed within North Dakota, let alone nationally, at the scale and timeline mandated by the Final Rule.

6. While CCS has great potential, many issues with implementing CCS for electric generation at the scale and speed required by the Final Rule remain unresolved. While North Dakota industry and regulators are actively pursuing promising solutions to those issues, the technology is not yet where it would need to be to meet the requirements of the Final Rule. And, if North Dakota cannot implement CCS within its boundaries at the scale and speed

required by the Final Rule, it is highly unlikely the rest of the country would be able to do so, as North Dakota has been a national leader in developing and implementing CCS.

7. Unplanned outages attributable to the capture plant, leaking heat exchangers and equipment scaling with calcium deposits, wet coal, plugging, issues in the powerhouse, and water cooling issues are some of the technology issues overlooked or given short shrift by EPA.

8. Indeed, none of the examples of successful plant operation cited by the Final Rule as the basis for claiming CCS is feasible at scale required by the Final Rule would meet the standards of the Final Rule. As analyzed and explained by the University of North Dakota's Energy and Environmental Research Center (EERC), 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%." EERC, *Examination of EPA's Proposed Emission Guidelines Under 40 CFR Part 60, Final Report 2023-EERC-08-04*, Aug. 2023, at 5-6 (State of North Dakota, Comments on EPA's Proposed Rule, Aug. 8, 2023, Ex. 1).

9. Consequently, the Final Rule's mandated compliance deadlines are unrealistic and unattainable.

<u>Impact of the Final Rule on North Dakota and NDDMR</u>

10. The Final Rule directly impacts 14 electric generating units in North Dakota, and indirectly impacts five active coal mines mining coal to feed steam boilers for electric generating plants in North Dakota and several hundred potential storage and enhanced oil recovery sites across the State.

11. The Final Rule will also directly impact North Dakota's regulatory programs for CCS projects, to include storage facilities, pipelines, survey and geologic work regarding CO2 injection, and many other related programs.

12. NDDMR has already expended significant resources to review the November 2021 proposal and the December 2022 supplemental proposal. And NDDMR has worked closely with its regulatory partners in the State to understand the scope, direct implications, and indirect implications of the Final Rule on the State.

13. Since the Final Rule has been released, NDDMR is preparing to expend significant additional resources in collaborating and coordinating through the NDIC in developing a range of regulatory responses to the Final Rule.

14. If the Final Rule is not stayed, NDDMR estimates that it will need to dedicate at least 28,000 hours of staff time to assessing regulatory responses and options for trying to implement the Final Rule. Each storge facility application requires one FTE employee approximately one year to complete the draft application, DEQ consultation, final application, public notice, hearing, commission order, and appeal period procedures. In order to meet the compliance deadlines set by the Final Rule, NDDMR would need to begin incurring those costs immediately. The six storage facilities currently permitted by DMR have demonstrated that approximately three years are required for site screening, seismic characterization, stratigraphic test drilling, computer simulation, and project design. Approximately one year is required for the regulatory process described previously, and approximately 3 years are required for carbon capture facility and storage facility construction. Based on this experience, in order to achieve project start-up by the 1/1/2032 rule compliance date a potential North Dakota project operator would have to begin the

process no later than 1/1/2025. In the vast majority of states that do not have Class VI primacy, where the regulatory process is more than 2 years, it will be impossible to meet the rule compliance date.

15. Additionally, if the Final Rule is not stayed, there is a strong likelihood that the partnerships and investments that have driven the development of CCS within North Dakota and around the country will be disrupted or destroyed. If industry and investors conclude that it is simply infeasible to meet the unrealistic standards and unreasonable timelines demanded by the EPA in the Final Rule, they may very well choose to cease investing in CCS or to cease operating altogether. If this were to happen, decades of tireless work and investment on the part of the State of North Dakota would be wasted, and the potential for CCS to help the State of North Dakota and its people utilize the State's abundant storage pore space potential and hydrocarbon resources would be killed before it was ever given a chance to mature.

16. In short, complying with the Final Rule will impose substantial costs and an administrative burden on NDDMR, and those costs will begin to accrue immediately. These costs and burdens will impede NDDMR's ability to perform its many other duties in service of North Dakotans and will impose a significant burden on resource-constrained state budgets. But worse, if the Final Rule is not stayed while this litigation plays out, its unattainable goals and unrealistic timelines stand a very real chance of thwarting the widespread implementation of CCS before the technology's true potential is ever reached.

I declare under penalty of perjury under the laws of North Dakota that the foregoing statements are true and correct to the best of my knowledge.

Executed in Burleigh County, on 5/13/2024

Lynn D Helms

Lynn Helms
Director
N.D. Department of Mineral Resources

EXHIBIT 17

DECLARATION OF ROBERT MCLENNAN

I, Robert McLennan, declare as follows:

1. My name is Robert McLennan. I am the President and Chief Executive Officer at Minnkota Power Cooperative ("Minnkota"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have more than 29 years of experience in electricity generation. I have been employed at Minnkota since 2011. I hold dual bachelor's degrees in history and political science, and psychology from the University of Jamestown. As President and CEO at Minnkota, my responsibilities include ensuring access to safe, reliable, affordable and sustainable electricity for 11 member-owner cooperatives in eastern North Dakota and northwestern Minnesota. This includes oversight of more the 400 employees and a budget of more than $450 million annually.

3. Minnkota is a member of the National Rural Electric Cooperative Association ("NRECA"), the Lignite Energy Council ("LEC"), and America's Power.

4. This declaration is submitted in support of staying the EPA's final rule entitled *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*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

5. I am familiar with Minnkota's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Minnkota as well as its suppliers, members, consumers, and employees.

6. Minnkota's planned "Project Tundra" facility would be the largest CCS project that the world has ever seen. Yet because of the Final Rule, it may never get built. That is because this state-of-the-art project is still

not enough to bring Minnkota's Young Station into compliance with the Final Rule. This despite the fact that $90 million and nearly a decade of planning have already gone into Project Tundra. Even if it were technologically possible to expand Project Tundra's scope—something no one knows, since no similar project has ever been attempted—the Final Rule does not leave anywhere near enough time for that expansion. Designing the current scale of CCS for Project Tundra took almost a decade. Yet the Final Rule requires Minnkota to update that design with a new, expanded CCS system and bring it into operation within about half that time. That is impossible.

7. Minnkota is a not-for-profit electric generation and transmission cooperative ("G&T") headquartered in Grand Forks, North Dakota. Minnkota is owned by 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota, which together serve some 160,000 member cooperative rate-payers. These communities depend on Minnkota to provide cost-effective electricity to sustain rural residences, businesses, schools, and farms. Minnkota also serves as the operating agent

for Northern Municipal Power Agency, which is headquartered in Thief River Falls, Minnesota. Since its formation in 1940, Minnkota has been committed to delivering safe, reliable, affordable and environmentally responsible energy to its member-owners.

8. Electric cooperatives, like Minnkota, sell most of their power to households rather than businesses unlike investor-owned utilities ("IOUs"), and serve predominantly rural areas. They operate at cost and without a profit incentive and are owned by the members they serve with no independent stockholders. Because costs of cooperatives are borne by fewer consumers, most of which are families, rate affordability is crucial to consumer-members. In addition, cooperatives have greater infrastructure needs due to the rural communities they serve, which provide fewer meters per mile of transmission lines. In fact, data from the U.S. Energy Information Administration show that cooperatives serve an average of eight consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line. In contrast, investor-owned utilities average 34 customers and collect $75,500 per mile of line.

9. Minnkota owns or operates one lignite coal mine-to-mouth power plant, the Milton R. Young Station (“Young Station”). Young Station is a two-unit, cyclone lignite coal-fired power plant located near the town of Center, North Dakota. Minnkota owns and operates Unit 1, and it also operates Unit 2 on behalf of Square Butte Electric Cooperative. Square Butte is owned by the same 11 member-owner cooperatives associated with Minnkota, and it shares the same management. At Young Station, lignite coal is mined from land adjacent to the plant and is the only type of coal the plant is designed to burn. Not only does this plant provide highly reliable and affordable energy given the proximity and steady supply of lignite to the electric generating units, the “mine-mouth” model is cost-effective for dispatchable power.

10. Electricity generated by Minnkota is distributed through the Midcontinent Independent System Operator (“MISO”) regional transmission organization (“RTO”). MISO “operates the transmission system and centrally dispatched market” in fifteen states ranging from Canada down to the Gulf Coast. Across those states, it serves more than 42

million customers.[1] Minnkota and its system partners (Northern Municipal Power Agency and Square Butte Cooperative) have the capability of generating 1,425 MWs, which may be provided to MISO for scheduling and reliability purposes. Over half of the electricity generated by Minnkota is dispatchable power from coal sources, meaning it is available on demand, unlike power from wind and solar resources, which do not have on-demand capabilities. Dispatchable power is critical for MISO because MISO has small reserve margins, which is the amount of power needed to ensure demand is met and avoid failure of the grid.

11. Minnkota is proud of its extensive decarbonization efforts, including a renewable portfolio that comprises 42% of current generation resources.

12. In 2015, Minnkota undertook the role as lead sponsor of a carbon capture and sequestration ("CCS") project adjacent to the Young Station. This project, known as "Project Tundra," aims to treat the flue gas from the

[1] FERC, MISO, https://www.ferc.gov/industries-data/electric/electric-power-markets/miso.

Young Station's two cyclone lignite-fired coal units, located near the town of Center, North Dakota. Minnkota, as the owner-operator of Young Station, has a strong interest in and is uniquely positioned to evaluate the Final Rule.

13. Although Minnkota strongly supports investment in CCS technology, the Final Rule drastically overstates the technology's current and future capabilities, as well as the timeline in which CCS can feasibly be deployed. Other aspects of the Final Rule pose new, grave reliability concerns that will lead to additional premature retirements. All of this will only compound the existing shortage of reliable, dispatchable generation. As a small, cost-sensitive cooperative, these shortages are of particular concern to Minnkota. So too are the Final Rule's massive costs and aspirational timelines.

OVERVIEW OF THE FINAL RULE

14. The Final Rule establishes CO_2 emissions limits that States must apply to existing coal-fired units, under Section 111(d). 89 Fed. Reg. at 39840. It also establishes limits for CO_2 emissions from new gas-fired combustion turbines, under Section 111(b). *Id.* at 39902. Under these limits, both existing

coal-fired units and new gas-fired combustion turbine units must meet a stringent "presumptive standard of performance." *Id.* at 39836; *see id.* at 39823-24. That standard is the degree of emission reduction achievable by the application of 90% carbon capture and sequestration/storage ("CCS"). *See id.* 39801-02. Existing coal-fired units that do not deploy CCS must shut down (unless a State or federal regulator successfully invokes one of the Rule's complex and discretionary exceptions). New units that do not reduce emissions to meet the presumptive standard must drastically reduce their output of electricity.

15. The Rule divides existing coal-fired units into three non-overlapping subsets: two "subcategories" and one "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit makes a federally enforceable commitment to retire, and by the date of that retirement. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *See id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

16. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

17. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent "—*i.e.*, transforming a coal unit into one that combusts both coal *and* natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

18. Third, units that make a federally enforceable commitment to permanently cease operating by January 1, 2032 have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

19. For new and modified gas-fired combustion turbines, the Rule creates three subcategories, which are "based on electric sales (*i.e.*, utilization) relative to the combustion turbines' potential electric output to an electric distribution network." *Id.* at 39908.

20. "Low load" units are those that supply 20 percent or less of their potential electric output as net-electric sales. *Id.* at 39917. They must use lower-emitting fuels. *Id.* "Intermediate load" units are those that supply more than 20% but less than or equal to 40% of their potential electric output as net-electric sales. *Id.* These units must use highly efficient simple-cycle turbine generation technology. *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of

performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

MINNKOTA'S EXPERIENCE WITH CCS

21. Minnkota and its project partners are pursuing construction of a CCS project adjacent to the Young Station known as Project Tundra. If it commences operation, it will be North America's largest CCS facility in scale. The project will treat approximately two-thirds of the flue gas of Units 1 and 2 to reduce and capture CO_2 emissions. The project is designed to capture CO_2 at a capture efficiency of approximately 95% of the treated flue gas from either unit at the Station, with the CO_2 stored more than a mile underground. The project will be two and a half times the size of the Petra Nova project that is located in Texas (as discussed below).

22. Project Tundra was first conceived in 2015. At this time, commercial operation is projected to begin in 2029 (if at all). That is a 14-year runway, which is almost *triple* what the Final Rule contemplates. And even

with all that extra time, **Project Tundra *still* would not fully comply with the Final Rule.**

23. Minnkota's experience with Project Tundra shows that 90% capture of carbon emissions using CCS is not adequately demonstrated and is not achievable as conceived by EPA. Project Tundra has been in development for almost a decade (since 2015).

24. Minnkota has spent approximately $90 million on design, engineering, consulting, site studies, and numerous other pre-construction activities. Approximately $60M of that investment was State and Federal government-funded. Even with all that investment and time, Minnkota has not made a final investment decision nor issued full notice to proceed with construction of Project Tundra. Instead, Minnkota anticipates making a decision about whether to go forward with the project later this year. Even if Project Tundra does go forward this year, commercial operation is not anticipated to occur until 2029.

25. To support EPA's contrary view, the Final Rule identifies only a small list of projects. SaskPower Boundary Dam Unit 3 is a 110 MW lignite-

fired unit in Saskatchewan, Canada. But it has been plagued with shutdowns and unexpected maintenance, and it has never been able to consistently achieve 90% carbon capture using CCS. The Petra Nova capture facility (a 240 MW capture at Parish Generating Station in Thompson, Texas) operated for three years between 2017 and 2020 and has only recently begun operating again. It is the *only* CCS system that has *ever* operated at a coal-fired facility in the United States. Plant Barry had a small pilot CCS project (a 25 MW slip stream capture system in Mobile, Alabama). The project was not comparable to the commercial scale generation that the Final Rule addresses. In other words, none of these projects have demonstrated successful, continuous operation of CCS at a 90% capture rate on a scale than could even conceivably be deployed to accommodate larger power generating units in this country.

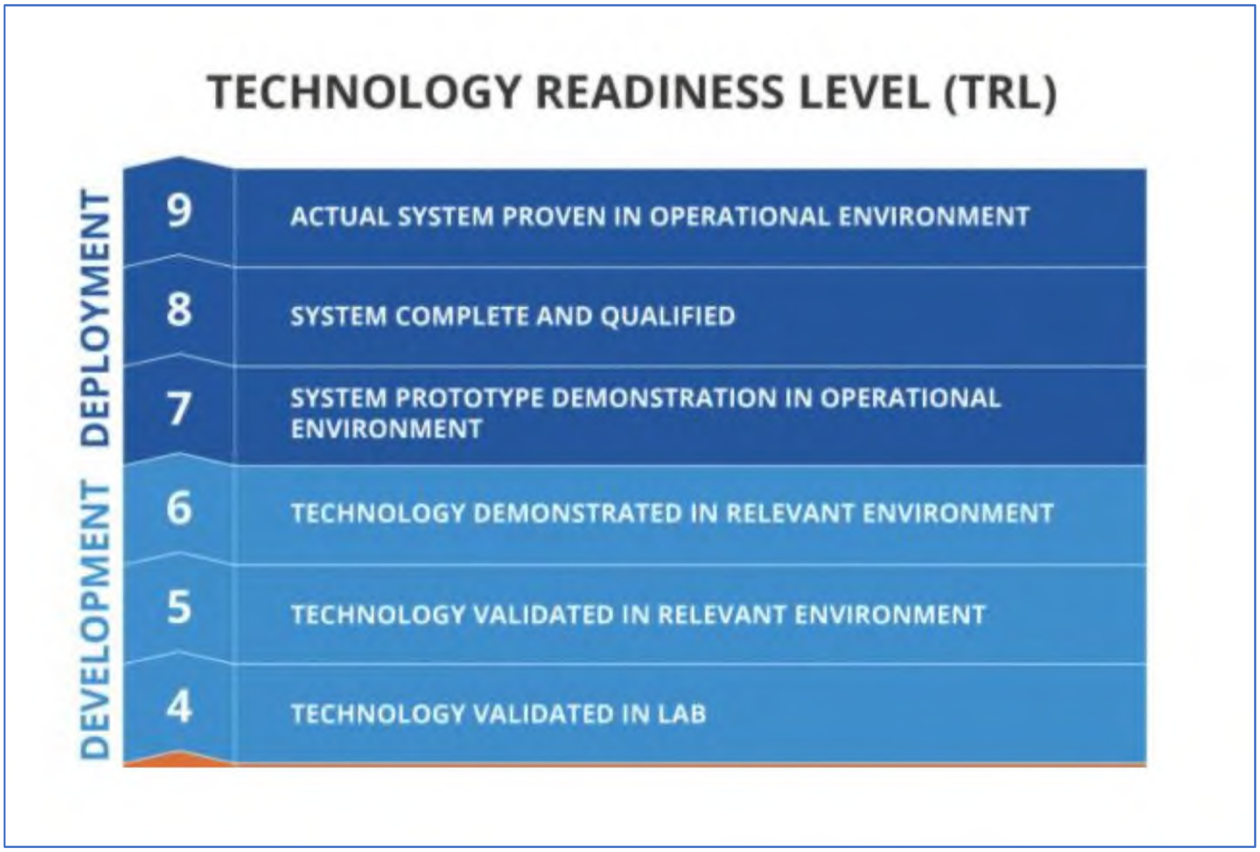
26. Minnkota's experience with Project Tundra versus EPA's assumptions in the Final Rule are starkly different. With respect to the storage component of the CCS process, Minnkota agrees with EPA's assessment that geologic sequestration of captured CO_2 is available in some

parts of the country, such as in North Dakota. Yet, it is not available universally. Many of the other assumptions in the Final Rule are similarly inconsistent with Minnkota's experience.

A. CCS technology has never been demonstrated.

27. CCS is potentially feasible, but it has not ever been adequately demonstrated. To be adequately demonstrated, CCS must be possible at all sites with existing coal-fired units, at all boiler-types, and at all loads. Minnkota's experience confirms this is not true. Of most significance, CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU.

28. Project Tundra is financed as a Technology Readiness Level (TRL) 7 project. TRL 7 projects are defined as "system prototype demonstration in an operational environment." TRL 7 projects have results from testing a prototype system in an operational environment but the technology has not been proven to work in its final form and under expected conditions to achieve TRL 8 status. TRL 9 projects are proven in the operating environment, as the graphic below illustrates:



29. The units at Young Station are a 455 MW unit (Unit 2) and a 250 MW unit (Unit 1). Yet Project Tundra only has capacity to treat 530 MW, with Unit 2 as the principal design unit.

30. If carbon capture were "demonstrated," as EPA claims, then Minnkota and its partners would not be able to finance Project Tundra as presently planned. Project Tundra is requesting financing, in part, as a demonstration project through funds from the Department of Energy's ("DOE") Office of Clean Energy Demonstrations ("OCED"). The Bipartisan

Infrastructure Law enacted in December 2021 created the funding opportunity for demonstration projects. But funding is not available for technologies that are proven at a commercial scale. To obtain funding from OCED, DOE looks at "technology readiness levels." It provides funds to projects that show advancing technology. The Project Tundra demonstration results from the bold investment to take CCS farther than before. The Project seeks to advance the technology readiness level of CCS by scaling up the technology (2.5x), applying it to lignite-fired coal units, and showing successful operations in the extreme weather climate of the upper Midwest. None of that has been done before.

31. Minnkota has acknowledged and carefully calculated the technology risk, taking account of site-specific variables. A crucial assumption in Minnkota's calculus is that the Young Station units may operate and generate electricity even if the CCS equipment has an outage. In other words, if equipment issues arise – whether due to the CCS technology, equipment, increased scale, extreme temperatures, or variability in flue gas load – the CCS system may take a forced outage. Meanwhile, the Young

Station units are able to generate electricity and emit flue gas through the current stack configuration while CCS is down and as the CCS starts up after outage. Thus, the risk of equipment failure is much less detrimental than if the entire Young Station must come offline for the entire duration of the CCS plant forced outage. In that event, Minnkota would be hedging its ability to meet generation needs on the CCS project equipment, a much different risk proposition for Minnkota's member-owners. Yet the Final Rule would compel consideration of this very result.

32. Carbon capture at a large-scale coal-fired unit or any natural gas unit has not been demonstrated. In fact, Project Tundra seeks to prove that large scale coal-fired application is possible. Project Tundra aims to capture the CO_2 emissions equivalent to a 530 MW unit. Project Tundra's scale will be the largest capture system in the world and will employ the largest single train system (i.e., all CO_2 sources fed to a single absorber) that has been built by any project manufacturer. But even the largest designed train is **still insufficient to cover EPA's anticipated scope,** which in Minnkota's case

would be 705 net MW of flue gas. An additional CCS train would be necessary.

33. Similarly, carbon capture is not adequately demonstrated to continuously achieve 90% capture of CO_2. Project Tundra is **<u>designed</u>** to capture 95% of the CO_2 in the flue gas when CCS is at **<u>full load</u>** and receiving flue gas from a combination of Unit 2 and Unit 1. The carbon capture process uses a complex chemical reaction to separate the CO_2 from other constituents in the flue gas and then prepare captured CO_2 for storage. Carbon capture efficiency and the operating implications on other important process parameters when the flue gas stream is at a lower load is not yet demonstrated or fully understood. Project Tundra's full load 95% design rate may not apply at lower flue gas loads.

34. Minnkota has no technical data or testing assurance that EPA's value of 90% carbon capture can be achieved across varying unit loads. In addition, weather (seasonal temperature) impacts are anticipated to affect the CCS equipment function. Based on Minnkota's understanding from project development, this demonstration project will help to provide

information on operation, which are presently at scale not demonstrated. The parameters for Project Tundra were never dependent on achieving a specific capture percentage continuously. Further testing and vendor information is necessary to target an achievable capture percentage that could be applied to all unit sizes, project scales, weather conditions, pollution control trains, and load levels with a margin for compliance. A margin for compliance would also be required.

B. CCS causes reliability issues that remain unresolved.

35. The Final Rule all but ignores the practical consequences of CCS. The electrical and steam requirements of a capture system are consequential. The electrical and steam requirements of carbon capture systems will reduce availability of a significant amount of generation from the grid in four ways: (1) Inadequate scale of CCS systems to treat the flue gas of a large unit; (2) Forced outages due to CCS equipment; (3) Inability to achieve 90% CO_2 removal at all loads; and (4) Diversion of electricity from the grid to run the CCS system.

36. In Project Tundra's case, 205 MW from the Young Station units is needed just to operate the adjacent CCS facility. In total, the CCS demand is about 31% of the Young Station's net capacity. This value is equivalent to retirement of a smaller generating unit. The cumulative demand to serve multiple CCS facilities—which is what the Final Rule contemplates—would severely strain the grid. That means that about 205 MW of the 734 MW Young Station would be needed to support CCS at Young Station rather than for sale as electricity on the market. CCS projects across the country would, if attempted, cause removal of megawatts from the nationwide grid, exacerbating reliability concerns that should be studied.

37. Forced outages due to CCS equipment failures will also remove generation from the grid. At present, no regulatory requirements constrain the Young Station from operating *even if* the CCS system experiences a malfunction. It is crucial to preserve the ability for units to function in must-run situations to abate a grid emergency.

C. CCS's tremendous expenses are possible only with support from government funding.

38. CCS Projects are very expensive due to development, one-time capital costs, and ongoing operating costs. Project Tundra is estimated at a cost of over $1.6 billion. The project will be financed by utilizing 45Q federal tax credits, which are currently $85 per ton of CO_2 that is captured and stored in a geologic formation deep underground. Permitting is completed for an adjacent second CO_2 storage site. If this federal subsidy were not in place, the project would not be economical. These costs are even more substantial for smaller generators, such as cooperatives.

39. Financing options are essential but limited. CCS projects are only possible through multiple funding sources. Project Tundra will use DOE funds, including assistance from the Inflation Reduction Act, and Department of Agricultural Rural Utilities Services ("RUS") funding. And the State of North Dakota is providing a $250 million loan to assist the project. Private loans are more challenging to obtain for demonstration projects. Projects of the scale required by the Final Rule would require

similar or greater levels of funding which will inevitably constrain the market and the funding opportunities available.

D. CCS storage is not achievable nationwide.

40. Many areas of the country do not have the geology to support sequestration. The Young Station happens to be placed on ideal geology for safely sequestering carbon, as demonstrated in the figure below. However, much study was necessary to arrive at this conclusion. In 2005, the Energy & Environmental Research Center ("EERC") at the University of North Dakota started characterizing the geology within the state and targeting storage formations. It took the EERC **over a decade just to characterize the geology**. Most sites do not have a deep porous rock layer to hold the CO_2, nor do they have overlying cap rock layers that will seal the CO_2 in the storage formations. Sites that do not have this geological setting must transport the extracted CO_2 to geology that is secure for storage. Dedicated piping must be available, adding even more cost to a project.

41. States with oil and gas frameworks, like North Dakota, will have a shorter timeline for exploring and permitting storage. North Dakota has an oil and gas and mining regulatory framework to study storage geology and issue permits. Many states do not have regulatory frameworks nor staff with any experience in this type of natural resource development. Time would be necessary to enable those states to develop a regulatory framework that supports sequestration and drilling and addresses ownership of natural resource pore space to lessen the possibility of future legal challenges for projects and permits. Further constraining the timeframe is EPA's own regulatory backlog, to obtain an EPA Underground Injection Control Class

VI permit to allow storage of CO_2 is an arduous process. A tremendous amount of information is needed. For example, EERC needed over a decade to characterize the geology. After that characterization, in 2020, Minnkota drilled two characterization wells to gather the necessary geologic data to support a permit application. This step was required to obtain a complete application.

42. Class VI permits are also expensive. For Project Tundra, the necessary storage permit cost was in excess of $30 million. This cost is likely reduced because the work was performed during the COVID-19 pandemic lockdown when rig costs and labor were less expensive due to availability. In the future, the cost might be double, particularly when utilities are competing over limited drilling resources. And Class VI permitting is a lengthy process. North Dakota is one of only three states with primacy to issue Class VI permits. North Dakota engaged in two full sessions of state lawmaking to enact laws required for EPA to grant primacy. Sources in all other states must look to EPA to grant Class VI permits. At present, 33 permit

applications are pending. Under the Final Rule, the backlog of pending applications will only increase.

E. Even attempting CCS takes massive amounts of time.

43. The Final Rule's timeline requires CCS to be fully operational by January 1, 2032. This time frame cannot be achieved.

44. For Project Tundra, project development took almost nine years of study and engineering analysis necessary to support a final decision on construction, despite exceptional geology at the Young Station. Carbon capture front-end–engineering-and-design ("FEED") studies take a minimum of 18 months (6 months for Pre-FEED studies plus 12 months minimum for a FEED study). Only four to five vendors actually have the capability to launch CCS projects. Minnkota has identified only two of those vendors able to develop CCS operations at the scale of Tundra.

45. For Project Tundra, the manufacturer selected, Mitsubishi Heavy Industries America, Inc., has been studying the flue gas characteristics of the Young Station since 2015. These studies are necessary to ensure successful capture solvent performance.

46. Environmental permitting has played a significant factor in the project timeline. The CCS facility requires water permits, an air permit, and high voltage transmission changes at the plant (re-routing).

47. Due to federal funding, the financing process itself is also subject to National Environmental Policy Act ("NEPA") environmental reviews, which can also add significant delay. Project Tundra has experienced NEPA delays. NEPA review performed through the DOE CarbonSafe Project is still ongoing. It began in 2021 to prepare the documentation necessary to submit the Environmental Consideration Summary to DOE for a determine of the type of NEPA assessment required. DOE made the decisions that an Environmental Assessment ("EA") was necessary in 2022. Two years later (2024), Minnkota is still waiting on a Finding of No Significant Impact ("FONSI") because two rounds of comments were needed. In total, the Project Tundra NEPA process has taken over three years and is still not complete.

48. Once FEED studies, permitting, and other project development work is complete, the actual construction timeline will take approximately

50 months. Since some equipment is fabricated off-site, it must be ordered to specifications well in advance. Delays are possible due to labor storages or supply chain issues.

49. Construction timelines are likely to be impacted by the demand the Final Rule would place on the small number of vendors available to develop and construct CCS projects. The construction vendors that are needed to construct CCS projects are the same vendors that undertake other infrastructure and labor-intensive projects for the power and industrial sectors. The Final Rule will cause simultaneous new CCS projects for coal and gas that will flood the field at the same time due to the concurrent due dates for these projects. In addition, EPA has further exacerbated labor demands due to the environmental upgrade projects that will be necessary to comply with the other environmental rules released along with Final Rule, including the Mercury & Air Toxics Residual Risk and Technology Review, Effluent Limitation Guidelines, and labor-intensive projects required to comply with new Legacy Coal Combustion Residuals regulations. This

demand will drive costs up for limited contractor resources and delay projects.

50. Supply chain delays will increase the time necessary to achieve commercial operation. For CCS projects, the present lead times for a transformer and power distribution center ("PDC") required for the CCS system is 94-110 weeks, based on recent contractor inquiries. These components are essential to any CCS project. That number will only grow as the Final Rule takes effect.

51. It took four years to obtain the Class VI permit for Project Tundra, including characterization of the geology for the permit application, completing the Class VI permit application, holding hearings, and obtaining the final permit. Minnkota anticipates that sites in states without a subsurface regulatory framework and primacy will require much more time. The CO_2 pipeline from the generating unit to the storage site requires additional time. Project Tundra did not require a long pipeline—only a quarter mile pipeline from the CCS equipment to the injection site on plant

property. The pipeline siting process was part of storage permitting. This is not likely to be the case for most CCS projects.

52. To summarize, **Project Tundra would not be completed in the time EPA has proposed, had the project begun today or even 4 years ago**.

THE IMPACT OF THE FINAL RULE ON MINNKOTA

53. Minnkota has no plans to retire Young Station, which is a key generation asset. But complying with the Final Rule will require substantial expenditures. The Young Station is home to the Project Tundra CCS project. **But even *with* Project Tundra, the Young Station cannot comply with the Final Rule**—despite more than approximately $1.6 billion of costs and what will be 15 years of project development efforts from conception to operation in 2029. This leaves Minnkota with two principal choices: Comply with the CCS baseload coal option or retire the Young Station. The latter would require Minnkota to build replacement generation.

54. *Using Project Tundra to Comply with the Rule.* The Rule jeopardizes Project Tundra's viability. If it is possible at the designed scale at all, achieving 90% carbon capture at Young Station would require

redesigning the Project Tundra CCS system to capture *all* of the CO_2 from both of the units at Young Station. As currently designed, Project Tundra would capture over 70% of the CO_2 from station-wide units.

55. Complying with the Final Rule's 2032 deadline would require Minnkota to immediately begin design and development and negotiate project contracts by the end of the current calendar year (at the very latest). Minnkota would need to completely redo engineering, conduct new FEED Studies, incur additional project development costs, and redo environmental permits, all of which would need to be scheduled and paid for immediately.

56. If Minnkota were to increase the scale of Project Tundra to capture an additional 205 MW (or roughly 28% of the total net load), it would cost an estimated $10-40 million in development costs alone. As a small cooperative, Minnkota does not have the resources to quickly or easily expand the project.

57. Even if resources were available, the delay for redesign and re-permitting efforts would set the project timeline back a minimum of 12 months. It is more likely that the project delay would be much longer

because Minnkota could not order key pieces of equipment that have a long wait-time (CCS transformer and CCS Power Distribution Center) until redesign of the CCS facility.

58. It is unlikely that Minnkota can build a larger scale CCS system to be available by 2032. Such a system would require new carbon capture Pre-FEED and FEED studies, environmental permitting, and site changes at the plant (transmission re-routing). The actual construction timeline will take three to four years. New equipment to cover the additional flue gas must be fabricated off-site and ordered to specifications in advance. Construction timelines would be impacted by the demand the Final Rule places on the small number of vendors that develop and construct CCS projects. Minnkota does not have adequate time to develop, finance, design, and build a new capture train to further increase the project scale. Minnkota estimates up to three years for redesign, re-permitting, financing, and compliance with environmental requirements, such as NEPA. It is uncertain whether the plant even has enough space to site a new or substantially enlarged absorber, which would be required to handle additional flue gas.

59. Minnkota has already expended $30 million dollars furthering development of Project Tundra. To have to add to the scale of the CCS process would result in significant delay to project development, design, equipment, and contractor, and result in substantial expenses that Minnkota could not bear as a small entity on top of the investment costs for Project Tundra.

60. Minnkota has advanced CCS technology for the benefit of the U.S. government and coal plants across the country, but Minnkota's years of planning, development, and acquiring funding for Project Tundra will have been for nothing if it cannot fully operate this technology as originally intended as a result of the Rule. Minnkota's resource planning has relied on this Project, rather than development of natural gas or other reliable resources of generation. This is at a huge cost not only to Minnkota, but all its members, customers, and rural Americans who depend on low-cost reliable energy. If even possible under a 2032 timeline, it would be extremely costly for Minnkota to have to entirely re-evaluate its long-term resource planning and begin immediately investing in the development of natural

gas, including siting a pipeline, design and engineering, and permitting, to comply with this Rule, all while retiring its existing coal asset—which has significant federal debt held against it—and trying to provide low-cost baseload energy to its customers.

61. If the Final Rule takes effect, electric markets will be highly constrained, as owners across the country will see reductions in their generation portfolios. Rather than becoming solely dependent on purchasing power from the constrained MISO market, the most likely cost-efficient option to address the diverted load of CCS is to build new generation.

62. *Compliance by Co-Firing is not an option for the Young Station.* Without significant study and development time, natural gas co-firing is not feasible or cost-effective at Young Station. The Final Rule allows affected EGUs to remain in operation through 2039 if they begin co-firing with 40% natural gas by 2030. There is no supply of natural gas within 30 miles of the Young Station. It is unlikely that a gas pipeline could be permitted and constructed in time for the Final Rule's deadlines. Even if supply were

available, the costs for retrofitting Young Station to co-fire with natural gas are infeasible—especially since affected EGUs would be required to shut down soon after installing this new equipment. The "medium term" compliance path is thus unavailable to Young Station.

63. *Retirement of Young Station would have significant costs*. If the Final Rule's requirements force Minnkota to abandon Project Tundra, the only remaining option for the Young Station would be retirement. This would have substantial costs for Minnkota, as well as for the lignite mine adjacent to Minnkota's Young Station, which was established for the sole purpose of providing fuel to the plant. Foremost, Minnkota would need to immediately begin securing reliable baseload power supply to offset the loss of the two units from Young Station. For the reasons discussed above (and below), action to secure replacement power would require significant expense and would need to begin immediately.

64. *Building Replacement Power to Serve Load.* The loss of Minnkota's only fossil generation station is very significant for the cooperative's ability to serve its customers with reliable, affordable electricity. It is unlikely that

Minnkota can build replacement generation to be available by 2032. However, Minnkota must begin spending money immediately for planning, design, siting, permitting, and construction.

65. *Reliability impacts of the Compliance Options*. Since the CCS technology has not been demonstrated at this scale, performance reliability early in operation is the largest risk, which under the rule introduces the likelihood to make an EGU less reliable, and thus to make unplanned outages more frequent and more severe. In other words, the DOE is funding demonstration of this technology at a commercial-scale because even while the technology has required technical and engineering adjustment to perform as guaranteed. The experience at Boundary Dam and Petra Nova shows that unplanned outages are a necessary aspect of attempting to use a new and underdeveloped technology like CCS. When scaled and applied for the first time at Young Station, CCS will undoubtedly cause upsets while operations are adjusted and fine-tuned. Minnkota anticipates this may be likely in the first 3 years after commercial operation date and that outages will need to be taken during that time. But unplanned outages increase

Minnkota's overall costs, hurt its relationships with members and consumers, and can even affect its contractual obligations with MISO.

66. Minnkota's ability to provide reliable power is especially important to the MISO system because the region is at a high risk of generation shortfall. Specifically, shift of new generation from thermal to wind and solar across the system is expected to cause a generation shortfall because renewable sources do not have the on-demand capabilities of the retiring thermal resources that can rapidly turn on and ramp up output when other generation (like solar) is unavailable.

67. Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur. And, the North American Electric Reliability Corporation (NERC) has reported the MISO region has an "elevated" potential for insufficient operating reserves in above-normal conditions, like during weather events or in the case of increased demand. Unplanned outages due to CCS would exacerbate already existing stress on the grid and risk generation shortfalls at times when providing dependable

energy is crucial, like during the winter. Therefore, the reliability impacts of CCS are another significant cost facing Minnkota.

68. If the Young Station had to prematurely retire due to the rule, Minnkota would not have time to construct replacement generation. Minnkota's only readily available option would be to increase its exposure to, and become reliant upon, an often volatile and constrained MISO market. Past market pricing demonstrates the extraordinary costs to purchase power from the market. In fact, these staggering costs have bankrupted a small utility recently (Brazos Electric Power Cooperative) due to power purchases during Winter Storm Uri from the ERCOT market.

69. *Power demands*. Increasing power demand in the MISO region, including in North Dakota, will similarly put more strain on the grid and more stress on generation. In the first quarter of 2023, North Dakota was the top state in economic growth in the country at 12.4%, as measured by gross domestic product ("GDP").[2] Economic prosperity is due to industry growth

[2] U.S. Department of Commerce, Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 1st Quarter 2023"