# United State Environmental Protection Agency

# Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule under Section 111(d) of the Clean Air Act

EPA-HQ-OAR-2013-0602

**Comments of Missouri River Energy Services**
**November 26, 2014**

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## Comments of Missouri River Energy Services

## 1. Executive Summary

Missouri River Energy Services (MRES) believes that the Clean Power Plan as proposed by the Environmental Protection Agency (EPA) under the Clean Air Act (CAA) section 111(d) is both illegal and unconstitutional. Its promulgation under 111(d) goes beyond its Congressionally delegated authority. The proposal overall, including specifically the structure it proposes for states to develop plans for implementation, creates constitutional issues that cannot be reconciled. For these reasons, MRES believes that EPA should withdraw the proposal.

Assuming that the proposal proceeds uninhibited by legal and constitutional infirmities, the Clean Power Plan is flawed in fundamental ways which must be corrected before the rule can be finalized. There are a number of key issues that demonstrate that this proposal in its current form will not work. Among those issues are the significant negative cost impacts, the unrealistic and unfair state goals, unrealistic timelines, the front-loaded glide path, and the threat that the plan poses to reliability.

As to the specifics of the proposal itself, EPA's state pathways which form the framework for state plans are not viable as drafted. Furthermore, the building blocks used to calculate state goals and provide compliance mechanisms are rife with issues that demonstrate that EPA does not understand the basic way the electric industry works, and also lacks a technical understanding of how those building blocks interact. The way in which the proposal addresses state plan approval, implementation and enforcement issues likewise reveals significant problems that should be corrected.

If it is possible to overcome the illegality and unconstitutionality of the Clean Power Plan, and to work through the many practical issues presented by the state pathways and the building blocks, MRES has identified a potential solution to make the proposal workable. MRES believes there is only one narrow way in which the proposal could possibly provide a viable mechanism for states to pursue $CO_2$ reductions under this unprecedented and complex proposed rule. Only a utility-driven portfolio approach could work as a state pathway for compliance plans, where states impose $CO_2$ reduction obligations only on the utilities that emit $CO_2$ in their state, and where all states honor the interstate nature of renewable and energy efficiency resources for use to offset $CO_2$ emissions to comply with the Clean Power Plan. Given the complexity of achieving such an outcome, however, it is most appropriate to withdraw the proposal, consider the many issues raised by stakeholders, and reconsider a more appropriate approach to achieve $CO_2$ reduction goals.

MRES is a member of, and supports generally the comments of the American Public Power Association, and offers the following additional comments on the Clean Power Plan.

## 2. Missouri River Energy Services Background

Missouri River Energy Services is a municipal power agency which supplies power and energy, and energy services to sixty-one (61) municipal utility members located throughout Iowa, Minnesota, North Dakota and South Dakota. Organized under Iowa Code Ch. 28E, we were created by the member communities that own us, and are a non-profit, customer-owned public entity, like the municipalities we serve. MRES is based in Sioux Falls, South Dakota.

### a. One coal unit in Wyoming: Laramie River Station

As a regional utility, MRES is unique in many ways. We rely on a single, base load coal plant located in Wheatland, Wyoming called the Laramie River Station (LRS).[1] The three units of LRS began commercial operations in 1980, 1981 and 1982, and produce 1,710 megawatts (MW). MRES, through its financing affiliate Western Minnesota Municipal Power Agency (Western Minnesota), owns 16.5% of LRS, and is entitled to approximately 282 MW. LRS has six owners, all of which are consumer-owned entities located throughout the region. LRS is the only MRES resource that qualifies as an "affected unit" under this rule that emits $CO_2$. MRES has no sales in Wyoming.

LRS provides 70% of the energy that MRES supplies to its members. Most members of MRES have allocations of federal hydropower that supply a portion of their needs, and MRES serves the balance of their community's need over and above the allocation. As a result, on average, MRES member communities rely on LRS for 40% of their power.

LRS is presently subject to an order of EPA regarding Regional Haze which requires the installation of Selective Catalytic Reduction (SCR) technology on all three units of LRS by 2019.[2] The remaining life of LRS is about 20-30 years. The cost to install the three SCRs at

[1] EPA has specifically asked for comment on "whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal, and if so, possible adjustments that should be considered." 79 Fed. Reg. at 34,887. As a municipal entity that is reliant on a single, coal-fired power plant for the majority of its power supply to member municipal utilities, MRES and its members are in a unique situation not contemplated in many aspects of the rule. These issues are identified throughout these comments and potential solutions are identified in Section 8.

[2] In the appeal of the Regional Haze Federal Implementation Plan of EPA, the United States Court of Appeals for the 10th Circuit has granted a stay pending appeal, and extending the compliance deadline for the course of the appeal. Wyoming v. United States Environmental Protection Agency, No. 14-9529 (No. EPA-R08-OAR-2012-0026), Powder River Basin Resource Council v. United States Environmental Protection Agency, No. 14-9530, Basin

LRS is approximately $750 million in total, $125 million for MRES and Western Minnesota alone.

When EPA's Regional Haze order is considered in light of EPA's Clean Power Plan under 111(d), this newest proposal will cause stranded costs and force our 61 member municipal utilities and their consumer-owners to pay for air quality control measures for which there is no value. The 111(d) proposal is premised on an assumption that all utilities own multiple and diverse plants and can shift generation within their portfolios to lower emitting generation. However, that option is not available to most small utilities, like MRES, that rely on a single base load coal plant to meet their needs.

### b. Sixty-one member municipal utilities' load in Iowa, Minnesota, North Dakota & South Dakota

All 61 MRES members are located in states remote from the Wyoming location of our single base load coal resource. Our multi-state load is located in Iowa, Minnesota, North Dakota and South Dakota. Our municipal utility communities range in size from nearly 40,000 to those with populations around 200 people. The average population of MRES member communities is nearly 5,000. In total, our members serve over 150,000 customer meters. Indeed, the MRES member communities are spread widely over a geographic area which is primarily rural in nature. Fifty-nine of the 61 members have allocations of federal hydroelectricity pursuant to contracts with the Western Area Power Administration (WAPA). Those members are in the process of executing new contracts with WAPA for hydropower that will begin in 2021 and run through 2050, and most of those agreements have been finalized. The WAPA allocations are fixed amounts of power, and MRES provides the supplemental power required to meet the entire electricity needs of nearly all of those members. In the case of Pella, Iowa, MRES provides 100% of the power that serves the community.

In addition to providing their citizens with reliable and low-cost electricity, nearly all MRES members also have energy efficiency programs to provide their consumer-owners with the opportunity to make the most economical use of electricity in their homes and main street businesses. MRES provides the Bright Energy Solutions® (BES) program to offer incentives to the end-use customers of our member utilities to implement a variety of energy efficiency measures.

The provisions of the 111(d) proposal are not suited to a situation where load is remote from generation, a characteristic that affect small municipal entities like MRES and its members. The building blocks all presume that load and generation are located in the same state. For MRES, that means our renewable wind energy resources in Iowa, Minnesota and North Dakota, as well as our nuclear resource, do not fall within the boundaries of the state of Wyoming where we emit $CO_2$. Furthermore, our energy efficiency and demand-side management programs in our member states generate $CO_2$ savings outside of Wyoming, in states where we have no affected units that emit $CO_2$ under the Clean Power Plan.

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Electric Power Cooperative v. United States Environmental Protection Agency, No. 14-9533, and PacifiCorp v. United States Environmental Protection Agency, No. 14-9534 (September 9, 2014).

### c. Clean, non-emitting energy resources of MRES

As mentioned above, the generating portfolio of MRES includes a variety of clean, non-emitting resources. MRES has taken, and continues to take, the initiative in working with its states – within existing state law and energy policy – to develop resource portfolios that are reducing its $CO_2$ footprint. At the present time, MRES has 85.7 MW of wind capacity from the following five wind energy resources:

- Hancock (IA) Wind Project, 3.3 MW
- Worthington (MN) Wind Project, 3.7 MW
- Marshall (MN) Wind Project, 18.7 MW
- Odin (MN) Wind Project, 20.0 MW
- Rugby (ND) Wind Project, 40.0 MW

MRES purchases the energy associated with the wind capacity from the wind projects listed above, and owns all of the environmental attributes associated with such generation. MRES also purchases 32 MW of nuclear power from the Point Beach Nuclear Plant located near Two Rivers, Wisconsin. MRES has a right to the non-emitting attributes from this facility. In addition, MRES is in the process of constructing, together with its financing affiliate Western Minnesota, the Red Rock Hydroelectric Project, a 36 MW hydroelectric plant located on Red Rock Dam on the Des Moines River near Pella, Iowa. The groundbreaking for this project was held on August 13, 2014. MRES renewable resources are part of the overall generation mix serving MRES members, and each member that has a power supply contract with MRES receives a proportionate share of each of the resources, in addition to their federal hydropower allocations.

Taken together, these facts about MRES and its members present a significant interstate issue for MRES and for small, regional municipal entities like it. If this EPA proposal moves forward, state plans should employ a utility-driven portfolio approach that recognizes the clean energy and energy efficiency – the non- $CO_2$ resources – owned by each utility, as well as the other building blocks. In the event that a utility has non-emitting credits, that utility should be entitled to use those non-emitting credits it owns to offset its $CO_2$ emissions in any state. It is only fair that the customers who paid for the renewable energy resource and the energy efficiency measures be entitled to take credit for them to offset their own emissions. Ratepayers are entitled to portability of their non-emitting resources in interstate commerce to use them for compliance against the $CO_2$ emissions from their resource located remote from their home state.

## 3. EPA's proposed Clean Power Plan is Illegal and Unconstitutional

EPA has only just recently been reminded that it cannot simply seize massive new regulatory authority for itself. In *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) ("*UARG v. EPA*"), the Supreme Court of the United States invalidated another of EPA's regulations aimed at limiting the emission of $CO_2$ because EPA overstepped the authority granted to it in the Clean Air Act. In doing so, the Court provided valuable lessons that EPA should heed in these proceedings. The Supreme Court made clear that regulation of greenhouse gases, including $CO_2$, cannot be "'extreme,' 'counterintuitive,' or contrary to 'common sense.'" *Id*. at 2441 (quoting *Massachusetts v. EPA*, 549 U.S. 497, 531 (2007)). Regulations often fall into those impermissible categories, the Court explained, when an agency interprets a statute in a way that "would … bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization." *Id*. at 2432 (citing *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 160 (2000)). The Supreme Court further cautioned that "[w]hen an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' … we typically greet its announcement with a measure of skepticism." *Id*. at 2,444 (quoting *Brown & Williamson*, 529 U.S. at 159).

### a. The Clean Power Plan is Illegal

EPA lacks the authority under the CAA to advance this proposal to a final rule. EPA is prohibited from regulating power plants under § 111(d) because it has regulated these same plants under CAA § 112. 42 U.S.C. § 7411(d)(1)(A).[3] In addition, CAA § 111(d) does not allow EPA to set the $CO_2$ reduction goals of each state or to go "beyond the fence" – that is, beyond the boundaries of a power plant which is the source of a pollutant – to regulate that pollutant. It is limited by statute to "establish[ing] a ***procedure*** … under which each State shall submit … a plan which … establishes standards of performance ***for any existing source*** …" *Id*. (emphasis added).

EPA cannot set $CO_2$ emission goals under §111(d). It statutory role is specifically limited to developing "*procedures;*" Congress clearly gave states the duty to "establish standards of performance[.]" *Id.* at 7411(d)(1)(A). The section of the CAA upon which EPA relies for this proposed rule, sets up a structure where EPA establishes procedures but it is only the state states that set standards. The plain language of § 111(d)(1) limits EPA's authority to prescribing

[3] What is known as section 111(d) of the Clean Air Act is found at 42 U.S.C. § 7411. It provides, in relevant part:

(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a ***procedure*** similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which

(A) establishes standards of performance ***for any existing source*** for any air pollutant (i) ***for which air quality criteria have not been issued or which is not included on a list published under section 7408 (a) of this title or emitted from a source category which is regulated under section 7412 of this title*** but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and

(B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410 (c) of this title in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title with respect to an implementation plan.

In promulgating a standard of performance under a plan prescribed under this paragraph, ***the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.*** (Emphasis added.)

"regulations which shall establish a procedure similar to that provided by section 7410" under which states set standards of performance for existing sources. In other words, EPA is required to set up procedures, but the states are given the authority and responsibility to establish the actual, substantive standards of performance. In contrast, Section 111(d)(2)(A) which authorizes EPA to set standards of performance, allows it to act (to impose a Federal Implementation Plan) only in situations where a state has failed to submit an acceptable plan.

Under Section 111(a)(1) and EPA's Subpart B rules, EPA is authorized only to set "*emission guidelines*" addressing factors relevant to the states' determination of the best system of emission reduction ("BSER") that has been "adequately demonstrated" and is "achievable" for each source type. *Id.* at 7411(a)(1), (d)(1); 40 C.F.R. § 60.22, 60.24(c). Importantly, EPA's *guidelines* are neither legally binding nor directly enforceable on sources — they simply set out considerations for states to address in adopting their own standards for existing sources based on long-standing principles of cooperative federalism upon with the Clean Air Act is based. *See* 40 C.F.R. §60.22. Accordingly, EPA's approach to determining BSER for limiting $CO_2$ emissions from EGUs may inform the content of EPA's emissions guidelines and the considerations states take into account in setting standards achievable by each source, but it does not give EPA authority to determine the resulting standards; the standard is to be established by the state. 42 U.S.C. § 7411(d)(1)(A). What the Administrator determines to be BSER is merely one of the many factors states must consider in determining the level and form of any existing source performance standard as applied to a specific Electric Generating Unit (EGU).

Another reason the plan is illegal is that it depends on "outside the fence line" mechanisms – not controls at the sources of the emissions – to achieve the vast majority of emission reductions. *See generally* 79 Fed. Reg. 34,856-34,858. In its proposal, EPA mandates $CO_2$ reductions for individual states. *Id*. at 34,833 (the proposed rule "lays out state-specific $CO_2$ goals that each state is ***required*** to meet…") EPA repeatedly refers to these as "goals" even though they are actually "binding," not optional as the word "goal" implies, based on four building blocks, only one of which involves reduction of emissions at the source. *Id*. at 34,892. "EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," The Brattle Group, June 2014, page 3, Table 1 (building block 1 accounts for only 12% of the total BSER $CO_2$ reductions in the Clean Power Plan).[4] The majority of the reductions are achieved from building blocks that are beyond the source of the $CO_2$ emissions. Further, EPA also employs these same building blocks as the compliance mechanisms upon which states are to rely for developing compliance plans.

Unlike previous EPA rulemakings under the CAA, EPA's proposal sets the compliance mandates based on actions taken by entities other than the affected EGUs. It compounds that statutory overreach by creating compliance mechanisms for states that mirror the same statutory overreach for state compliance plans. *Id*. at 34,877-34,892. Once a state plan is approved by EPA, it then becomes federally-enforceable. *See* 42 U.S.C. § 7411 (d)(2)(B). This entire scheme disregards the fact that EPA has no legal authority to impose federally-enforceable requirements or impose a Federal Implementation Plan to reduce pollution on non-EGUs (*e.g.*,

[4] Policy Brief available at http://www.brattle.com/system/publications/pdfs/000/005/025/original/EPA%27s_Proposed_Clean_Power_Plan_-_Implications_for_States_and_the_Electric_Industry.pdf?1403791723, last accessed November 24, 2014.

by setting state goals based partially on renewable generation and energy savings); it can only regulate the source of pollution. 42 U.S.C. §7411(d).

Finally, the proposal blatantly disregards the mandate that EPA must explicitly take into account the remaining useful life of the sources being regulated, *i.e*. power plants. *See* note 3. CAA 111(d)(2)(B) states "…the Administrator ***shall take into consideration***, among other factors, ***remaining useful lives of the sources*** in the category of sources to which such standard applies." *Id*. (emphasis added). The Clean Power Plan is structured in such a way as to eliminate useful life from the entire range of considerations for a state plan to take into account to achieve compliance. Although the proposal purports to take into account remaining useful life by "provid[ing] states with the flexibility to determine how to achieve reductions … and to adjust the timing in which reductions are achieved in order to address key issues such as cost to consumers, electricity system reliability and the remaining useful life of existing generation assets[,]" it is a baseless assertion. 79 Fed. Reg. 34,836.

First, the statute requires that the *Administrator* take into account the remaining useful life, not the state plan. Second, the proposal rigidly establishes deadlines for compliance. It sets both interim goals for 2020-2029 (the period referred to as the "glide path"), and final goals that must be achieved by 2030.[5] It does not give states meaningful control to "adjust the timing" of either the glide path or the final goal, despite its claims that allowing regulation of specific EGUs creates a situation where a state could potentially consider remaining useful life. 79 Fed. Reg. 34,926. There is virtually no way that a state plan can take into account remaining useful life given the interim goals and compliance time frames that are established in the rule.[6] The rigid compliance deadlines have effectively denied states any meaningful opportunity to use any "flexibility" in setting compliance for EGUs based on their remaining useful life. The failure of this proposal to meaningfully take into account remaining useful life is an illegal disregard of a statutory requirement. 42 U.S.C. § 7411(d)(2)(B).

The Notice of Data Availability (NODA) addresses some of these issues when it asks for additional comment on glide path issues and a book value approach to avoid stranded costs. 79 Fed. Reg. at 64,547-549. However, because it simply requests additional input, it too entirely fails to resolve the failure of the plan to provide meaningful consideration of the remaining useful lives of coal plants.

### b. The Clean Power Plan Encroaches on State Jurisdiction

In the Clean Power Plan proposal, the EPA asserts jurisdiction over matters traditionally reserved to the states as part of their long-standing police powers and related rights to set standards and

[5] In its Notice of Data Availability related to the Proposed Clean Power Plan (hereafter NODA), EPA solicits additional input on the 2020-2029 Glide Path. 79 Fed. Reg. 64,543, 64,548-549 (October 30, 2014). The suggestions for additional comment do not materially change the issue discussed here, and will be addressed later in these comments in Section 4.f.

[6] EPA asserts that "because of the flexibility for states to design their own standards, the states have the ability to address the issues involved with 'remaining useful life' and 'other factors' in the initial design of those standards, which would occur within the framework of the CAA § 111(d) plan development process. States are free to specify requirements for individual EGUs that are appropriate considering remaining useful life and other facility-specific factors." 79 Fed. Reg. 34,925.

rules within their own borders, and under the historical development of both the Federal Power Act and the CAA. As such, it is unlawful and should be withdrawn.

### i. The Federal Power Act bars the proposed regulation

The EPA proposal intrudes into the regulatory sphere explicitly reserved to the states by the Federal Power Act (FPA). A fundamental tenet of the FPA is the express division of authority between the state and federal governments over issues of generation, transmission, distribution, and sale of electricity. 16 U.S.C. §§ 824 – 824w (2012). The FPA acknowledges that "Federal regulation … extend[s] only to those matters which are not subject to regulation by the States[,]" thus preserving the traditional role of the states. *Id*. at 824(a); *see Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205, 218 (1964) ("*FPC v. SCE*"). For that reason, Congress limited the very terms of the FPA to federal regulation of "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce." 16 U.S.C. § 824(a). Furthermore, the provisions of the FPA also generally do not apply to the United States (and federal agencies, including federal power marketing administrations), to states, political subdivisions of states, and municipalities and their agencies (including state and local public power utilities such as MRES and its members), and to most rural electric cooperatives. 16 U.S.C. § 824(f).

The Clean Power Plan is an attempt by EPA to exercise federal jurisdiction over the most fundamental elements of the electric industry including basic generating resource decisions from constructing new resources to closing existing plants (and everything in between), as well as matters specific to retail issues. The FPA, Federal Energy Regulatory Commission (FERC) and the U.S. Supreme Court collectively have established that there is a "bright line" that places these issues squarely within state authority, and denies the federal government or its agencies the power to regulate in these arenas. *See FPC v. SCE*, 376 U.S. at 215. Thus, local service issues, including reliability of local service, authority over integrated resource planning, the need for additional generating capacity, the type of generating facilities to be permitted, and demand-side management, as well as the power to impose retail stranded cost charges, ratemaking, and even matters of retail transmission are all within the exclusive province of the states. *Id*.; *New York v. FERC*, 535 U.S. 1, 24, 122 S.Ct. 1012, 1026, 152 L.Ed.2d 47, 66 (2002) (citing Order No. 888, at 31,782, n.543 and n. 544); *Pacific Gas & Electric Co. v. State Energy Resources Conservation & Development Comm'n*, 461 U.S. 190, 212 (1983); *see also, e.g*., *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216, 224 (D.C. Cir. 2014) ("the Federal Power Act unambiguously restricts FERC from regulating the retail market").

The regulation of utilities is among "the most important functions traditionally associated with the police power of the States." *Arkansas Elec. Co-op. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983). *See also California Pub. Util. Comm'n*, 134 FERC ¶ 61044, 61160 (2011) ("[S]tates have the authority to dictate the generation sources from which utilities may procure electric energy."). Most — if not all — of the programs in building blocks 2-4 are within the exclusive purview of state regulators. These programs have been developed pursuant to well-established state sovereign powers over matters relating to electricity regulation, including determining the appropriate mix of generating resources within a state consistent with state energy policies. The Clean Power Plan and its building block approach completely disregard not only the historic role of the states, but the plain language of the FPA and Supreme Court rulings defining the line between state and federal regulation of the electric industry.

### ii. The Clean Air Act bars the proposal

The CAA establishes the right of states to set their own emission standards based on EPA guidelines, and EPA oversteps its authority by setting "binding" emission goals and compliance mechanisms. CAA 111(d) is a framework in which EPA can establish procedures to be used by the states to develop and submit a plan that sets the standards of performance and implementation plans. CAA 111(d)(1).

As noted above, EPA is barred by U.S. Supreme Court precedent from infringing upon a traditional state sovereign function unless Congress has adopted clear statutory language expressly authorizing the Agency to do so. *Arkansas Elec. Co-op.*, 461 U.S. at 377. *See New York v. United States,* 505 U.S. 144, 112 S.Ct. 2408, 120 L.Ed.2d 120 (1992)*; see also* "Federalism, State Sovereignty and the Constitution: Basis and Limits of Congressional Power," Kenneth R. Thomas, Congressional Research Service (Updated June 17, 2005) at CRS-1.[7] Nothing in the CAA expressly authorizes EPA to regulate the generation of electricity, the type of electricity, or other such energy regulatory matters traditionally reserved to states. As discussed above in Section 3.a., the CAA delegates to EPA the authority to establish *procedures* only, and reserves to the states the authority to set emission *standards*. 42 U.S.C. § 7411(d)(1)(A).

In addition, the Clean Power Plan's building blocks 2, 3 and 4 go where federal regulations have not gone before, and impermissibly infringe on state laws that take primacy. For example, state laws govern renewable energy and standards for its use within the state. *See, e.g*., Iowa Code § 476.41 to 476.48; Minn. Stat. § 216B.1691, subd. 2a; N.D.C.C. §§ 49-02-24 to 49-02-34; SDCL § 49-34A-101. It is within their authority to set up renewable energy credit trading programs. *See, e.g*., Iowa Code § 476.44; Minn. Stat. § 216B.1691, subd. 4; N.D.C.C. §§ 49-02-31, 49-02-33; SDCL §49-34A-95. Likewise, it is the state's role to establish energy efficiency and demand-side management requirements for utilities that provide consumers with electricity within their state. *See Electric Power Supply Ass'n*, 753 F.3d at 221; Iowa Code § 476.6.16; Minn. Stat. § 216B.241.

This proposal extends far into areas that are within the states' exclusive jurisdiction. The states in which MRES operates – Iowa, Minnesota, North Dakota, and South Dakota – are each structured in the traditional manner, with vertically-integrated utilities (no retail restructuring). Under state law, state and local regulatory bodies are empowered to set rates, terms and conditions of service. Iowa Code § 476.1; Minn. Stat. ch. 216A.01; N.D.C.C. ch. 49-02; SDCL ch. 49-01. State utility commissions regulate the rates of investor-owned utilities, and local governing bodies regulate the rates of municipally-owned and cooperative utilities under the authority of state law. In addition, the respective regulatory bodies also govern the resource planning of the utilities over which they have jurisdiction, consistent with state law and policy. Generation decisions are governed at the state level, not the federal.

The development of this division of responsibilities is no accident. States have the exclusive right to regulate the retail electricity market. *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216, 221 (D.C.Cir. 2014). In contrast, the Federal Energy Regulatory Commission has

[7] Report available at: http://www.au.af.mil/au/awc/awcgate/crs/rl30315.pdf (last accessed November 6, 2014).

jurisdiction over wholesale electricity markets. *Id.* EPA's Clean Power Plan encroaches impermissibly on both realms. The mechanisms of building blocks 2-4 are within the exclusive purview of state regulators. These programs have been developed pursuant to well-established state sovereign powers over matters relating to electricity regulation, including determining the appropriate mix of generating resources within a state consistent with state energy policies. *See, e.g.*, Minn. Stat. § 216B.2422 (state oversight of generation resource planning).

Specifically, municipal utilities are responsible not only for setting their rates, but also for making their resource decisions, both on the supply side and the demand side. Fifty-nine of Missouri River Energy Services' 61 members have allocations of federal hydropower which have served their communities with low-cost, non-emitting power for generations, averaging over 40% of their total power supply. The remainder of their power is acquired from MRES resources, which were first expanded in 2001 to include renewables in the form of wind power. Today, the MRES portfolio includes both wind and nuclear power to supply 16%-18% of our resources from non-emitting sources. Furthermore, MRES is in the process of constructing, in conjunction with its financing affiliate Western Minnesota, a hydroelectric power plant at the Red Rock Dam on the Des Moines River in Iowa. When complete in 2018, this project will add 36 MW of renewable resources to our growing portfolio. Furthermore, MRES launched its BES demand side management and energy efficiency program in 2008, and its Coordinated Demand Response (CDR) program in 2011, both deployed throughout our member communities in all four states to provide energy efficiency and demand response solutions to members and their customers.

MRES is a solid example of the initiative municipal utilities are taking, in working with their states – within existing state law and energy policy – to develop resource portfolios that are reducing their $CO_2$ footprint. By allowing municipal utilities to make their own resource decisions to meet state goals and mandates, MRES is able to carefully study and select those resource projects that best fit the needs of its 61 member communities in four states, and do so without creating major rate shock. The Clean Power Plan is the direct opposite of the thorough and deliberative process used by MRES and municipal utilities everywhere to provide reliable, cost-effective long term energy and energy services in a fiscally responsible and environmentally sensitive manner. In fact, the Clean Power Plan gives no credence to reliability, planning horizons, and power quality.

Congress has established a long-standing structure for the regulation of electricity markets, which vests the FERC with jurisdiction over wholesale electricity markets. *Electric Power Supply Ass'n*, 753 F.3d at 221. It has jurisdiction to enforce the FPA, which reserves matters of wholesale electricity and transmission to FERC. 16 U.S.C. Ch. 12. *See also* 42 U.S.C. §§ 7171-7172. EPA does not have authority to act in matters that affect the wholesale market, and the Clean Power Plan cannot be implemented without affecting wholesale markets, including the mix of wholesale resources a utility such as MRES uses to meet its needs. The overall intent of the proposed regulation is to force significant shifts in generating capacity in the wholesale market which squarely impacts both wholesale generation and transmission, and oversteps the authority of the EPA.

### c. The Clean Power Plan is Unconstitutional

In addition to the illegality of the EPA proposal under federal and state law, it is more significantly burdened by the fact that it violates several fundamental constitutional tenets. The structure of the EPA proposal relies on its directives to states to implement its proposal in ways that contravene traditional constitutional principles.

#### i. Tenth Amendment state sovereignty

The Clean Power Plan violates the Tenth Amendment to the United States Constitution because it oversteps the boundary between federally permissible regulation and those powers reserved to the states. The Tenth Amendment provides: "The powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people." The EPA proposal directly imposes on states the requirement to achieve the individual "goal" of a state-specific rate of $CO_2$ pounds per Megawatt-hour (lbs/MWh) emitted. The manner in which EPA sets the state "goals" – which are actually mandatory, binding standards that must be achieved in a stated time frame – and prohibits the states from exercising their control over both the standards and the manner in which such standards must be achieved during both the interim "glide path" period as well as the final compliance period, encroaches on the powers reserved to the states. In addition, the bulk of the Clean Power Plan is concerned with achieving $CO_2$ reduction through the use of building blocks 2, 3 and 4, all of which are matters of traditional state sovereign power which have not been specifically or unmistakably delegated to Congress or EPA. Here, the EPA attempts to improperly seek to control the manner in which states regulate private parties who may or may not emit $CO_2$, and tries to pass it off as a rule which merely regulates activities of the state itself directly. *See South Carolina v. Baker*, 485 U.S. 505, 514, 108 S. Ct. 1355, 1362, 99 L. Ed. 2d 592, 604 (1988).

First, by expressly setting the emissions rate that each state must achieve, the Clean Power Plan requires states to use their sovereign power to regulate the citizens and businesses within their respective borders. As a practical matter, there is no way that a state can comply with the mandatory emission rate without either forcing the state itself to undertake actions to reduce the $CO_2$ rate in its state or regulating the conduct of its private citizens that emit $CO_2$. The United States Supreme Court has drawn the line between the authority of the federal government to act and those instances in which the power is reserved to the states and their citizens under the Tenth Amendment.[8]

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[8] MRES has characterized this issue as a Tenth Amendment issue, but it is at the same time an Article I issue:

> In some cases the Court has inquired whether an Act of Congress is authorized by one of the powers delegated to Congress in Article I of the Constitution. In other cases the Court has sought to determine whether an Act of Congress invades the province of state sovereignty reserved by the Tenth Amendment. In a case like these, involving the division of authority between federal and state governments, the two inquiries are mirror images of each other. If a power is delegated to Congress in the Constitution, the Tenth Amendment expressly disclaims any reservation of that power to the States; if a power is an attribute of state sovereignty reserved by the Tenth Amendment, it is necessarily a power the Constitution has not conferred on Congress.

*New York v. U.S*. 505 U.S. 144, 155, 112 S.Ct. 2408, 2417, 120 L.Ed.2d 120, 137 (1992) (internal citations omitted).

In *New York v. United States,* 505 U.S. 144, 112 S.Ct. 2408, 120 L.Ed.2d 120 (1992) (*New York v. U.S.),* a provision of the federal act regarding low-level radioactive waste crossed the line. It demonstrates a situation where Congress reached beyond its Article I powers and infringed on the Tenth Amendment authority reserved to the states. As the *New York v. U.S.* Court acknowledged, "We have always understood that even where Congress has the authority under the Constitution to pass laws requiring or prohibiting certain acts, it lacks the power directly to compel the States to require or prohibit those acts." *Id.* at 166, 120 S. Ct. at 2423, 145 L.Ed. 2d at 144 (citations omitted). "The allocation of power contained in the Commerce Clause, for example, authorizes Congress to regulate interstate commerce directly; it does not authorize Congress to regulate state governments' regulation of interstate commerce." *Id.* Here, Congress has delegated to EPA its authority to regulate air quality, among other things. And, while EPA has authority pursuant to that delegation of authority to adopt regulations and procedures requiring or prohibiting certain acts, EPA – like Congress – lacks the authority directly to force states to require or prohibit those acts.

In this case, EPA's proposal to mandate $CO_2$ emission rate reductions for each state extends beyond the boundary of Congressional authority delegated to it. State sovereignty requires that states themselves be free to establish how a federal objective will be achieved. In *New York v. U.S.,* the Court held that Congress could not force states to take title to low-level radioactive waste and accept liability for it because it crossed the line between encouragement and coercion. 505 U.S. at 175, 120 S. Ct. at 2428, 145 L.Ed. 2d at 149. Here, Congress recognized that bright line and empowered EPA only to adopt *procedures*, and left to the states the authority to adopt *standards* and the methods to implement those standards; EPA has overstepped its delegated authority. *See* 42 U.S.C. § 7411(d)(1)(A).

As the Supreme Court has observed:

> [W]here Congress has the authority to regulate private activity under the Commerce Clause, we have recognized Congress' power to offer States the choice of regulating that activity according to federal standards or having state law pre-empted by federal regulation. *Hodel v. Virginia Surface Mining & Reclamation Assn., Inc.*, supra, 452 U.S., at 288, 101 S.Ct., at 2366. *See also FERC v. Mississippi*, supra, 456 U.S., at 764-765, 102 S.Ct., at 2140. This arrangement, which has been termed "a program of cooperative federalism," *Hodel*, supra, 452 U.S., at 289, 101 S.Ct., at 2366, is replicated in numerous federal statutory schemes.

505 U.S. at 144-145, 120 S. Ct. at 2,424, 145 L.Ed. 2d at 167. *See also Gregory v. Ashcroft*, 501 U.S. 452, 461, 111 S.Ct. 2395, at 2401, 115 L.Ed.2d 410, 424 (1991) ("[T]he States retain substantial sovereign powers under our constitutional scheme, powers with which Congress does not readily interfere.").

It is precisely because Congress has embraced the principles of cooperative federalism that it delegated to EPA limited authority under the Clean Air Act. That authority is limited expressly to the establishment of *procedures*, and for that reason both the attempt to set *binding* $CO_2$ emission limits on individual states and the express effort to define the mechanisms that states may use to achieve compliance (*i.e*. the building blocks) contravenes the constitutional limits of EPA's delegated powers. For these reasons, EPA must withdraw the Clean Power Plan proposal.

### ii. Fifth Amendment Takings Clause

The Clean Power Plan's approach to allow states to use utility-owned renewable energy and renewable energy credits (RECs) to meet a state $CO_2$ goal creates the potential for an unconstitutional taking of property without just compensation. It provides

> " … for renewable energy measures, consistent with existing state RPS [Renewable Portfolio Standards] policies, a state could take into account all of the $CO_2$ emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states . . .

Clean Power Plan, § VIII.F.6 (79 Fed. Reg. 34,921-34,922), EPA Technical Support Document (TSD): State Plan Considerations, at 84, 87. Furthermore, by suggesting that a state with a renewable measure in place which causes renewable investment in a separate state has the right to claim the out-of-state renewables as a $CO_2$ offset in its state compliance plan, the proposal doubles down by reaching across state borders to confiscate renewable energy and RECs of utilities and developers. The state-driven portfolio approach is one which EPA identifies as a structure for states to use to develop their compliance plans. 79 Fed. Reg. at 34,901; TSD: State Plan Considerations, page 5, § II. Under such a plan, individual states must assume the responsibility for meeting their specific $CO_2$ reduction goal established by the EPA, which is based on the generation located within each state's borders. Under the proposal, states are encouraged to use renewable energy as one of four building blocks to meet the compliance goal. Indeed, on average, EPA relies on renewable energy for more than 30% of the $CO_2$ reduction to be achieved. "EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," The Brattle Group, June 2014, page 3, Table 1 (renewable generation in building block 3 accounts for 33% of the total BSER $CO_2$ reductions in the Clean Power Plan).

While the proposal touts flexibility and offers "options" to states in developing compliance plans, the fact is that it sets up a structure in which states are empowered to confiscate for their own regulatory goals renewable energy and RECs – which are the property of utilities and developers – and use them to satisfy their individual $CO_2$ goal. Under a state-driven portfolio approach, state plans which include renewable energy for compliance will open the door for states to simply count all the renewable energy generated in the state and the accompanying RECs[9] to meet the compliance goal. As a result, the utility that owns the renewable energy/RECs will be prohibited from using those resources elsewhere because the Proposal expressly prohibits "double counting." 79 Fed. Reg. at 34,922. This is especially true in states which have a renewable energy mandate which already requires REC retirement for compliance with that separate state goal.

[9] Under this scenario, it is not clear whether a state plan would be required to honor contracts under which in-state renewable resources and RECs are sold to an out-of-state entity. The preamble is silent on this point, and does not make any indication that it recognizes that the RE/RECs are the property of utilities and not states.

For example, in Minnesota, the state has imposed a Renewable Energy Standard (RES). The state of Minnesota is served by a variety of fossil and clean generation, both in-state and out-of state, and by a variety of utilities based in- and outside of Minnesota. However, Minnesota's $CO_2$ goal is based on the generation located only in the state. The proposal allows Minnesota to structure its state plan to count toward compliance all of the RES RECs used in the state by out-of-state entities. However, MRES has no generation contributing to the $CO_2$ emissions located in the state of Minnesota. It does, however, provide renewable energy (RE) based on the state's mandate. That RE and the associated RECs come from facilities owned by Western Minnesota or contracts between MRES and wind developers, and has been bought and paid for by MRES members in not only Minnesota but also Iowa, North Dakota and South Dakota. Furthermore, that RE is located in not only Minnesota but also in Iowa and North Dakota (as well as a non-emitting nuclear resource in Wisconsin). Allowing the state of Minnesota to offset the emissions of its in-state EGUs with RE from a utility like MRES that does not even emit any $CO_2$ in the state constitutes a taking of MRES property for a public purpose without any compensation. *See also* discussion at Section 5.b. below. It is nothing short of requiring MRES to offset the emissions of another utility.

While MRES may have an RES compliance obligation in Minnesota, that does not entitle EPA to authorize the state of Minnesota to take the RE paid for by MRES members and their customers (which has not been used to meet Minnesota's RES, *i.e*. excess RECs) to meet its state goal to offset the $CO_2$ emitted by others. Furthermore, if neighboring states such as Iowa and North Dakota where MRES has contracts for RE and RECs take a similar approach, the same renewable energy and RECs could be claimed by multiple states to meet their state compliance plan under the EPA's flawed reasoning that a state policy that encourages the construction of renewables can be claimed by the state even if it is located out-of-state. It sets up a state versus state argument over which state's policy effectively induced the construction of the RE. Under either case, this element of the Clean Power Plan is an unconstitutional taking of private property without compensation, in violation of the Fifth Amendment to the United States Constitution.

#### iii. Article I Contracts Clause

Additionally, by authorizing state plans that enable states to take the renewable energy and/or RECs of utilities and others, the proposal also violates the Contracts Clause. MRES has several contracts with a number of individual entities for the output of wind projects *and* the associated RECs, totaling 85 Megawatts (MW).[10] A state-driven portfolio approach which adopts EPA's suggestion to use the renewable energy and RECs located in the state to satisfy a state goal will take that RE and RECs out of the hands of the purchaser MRES and into the hands of the state to meet its objectives. The Clean Power Plan expressly authorizes state plans that would have this very result. 79 Fed. Reg. 34,921-34,922.

Article 1, Section 10 of the United States Constitution, clause 1, provides in pertinent part: "No State shall … pass any … Law impairing the Obligation of Contracts[.]" However, this proposal authorizes states to take RE and RECs from its owners by disregarding the contractual rights of both the seller and the purchaser. It vitiates the obligation of the seller to deliver the RE and

[10] MRES also has a contract for non-emitting nuclear power from the Point Beach facility in Wisconsin, along with the environmental attributes associated with that power.

RECs to the purchaser, and substitutes the state as the beneficiary of the renewable contract (again, without compensation). This constitutes an undeniable “substantial impairment of a contractual relationship.” *See General Motors Corp. v. Romein*, 503 U.S. 181, 186, 112 S.Ct. 1105, 1110, 117 L.Ed.2d 328, 337 (1992). The construct of the state-driven portfolio approach, including its provisions allowing states to interfere with existing contracts for RE and RECs – both in-state and out-of-state – violates the Contracts Clause.

The Clean Power Plan embodies the mechanism by which EPA creates the authority for states to create a substantial impairment in the renewable energy contracts of utilities. First, it is undeniable that MRES and many utilities have such contractual relationships with renewable power producers, and that a regulation which allows the state to step in and use that RE to meet its $CO_2$ reduction obligation would constitute a change in law that impairs that contractual relationship, the first two elements in the test of a Contract Clause violation. *See id.* The final element, whether the impairment is substantial, while typically the subject of controversy, is also undeniable. *See id.* Where the regulation establishes the mechanism for the state to unilaterally use a utility’s resources for its own benefit there can be little doubt that there is a virtual “destruction of contractual expectations” and thus, a substantial impairment. *Energy Reserves Group, Inc. v. Kansas Power & Light Co.*, 459 U.S. 400, 411, 103 S. Ct. 697, 704, 74 L. Ed. 2d 569, 580 (1983).

These identified violations of the Contracts Clause, the Fifth Amendment’s Takings Clause and the Tenth Amendment demonstrate that the Clean Power Plan is unconstitutional and should be withdrawn. In addition, because the proposed rule is drafted in such a way as to provide optional compliance paths for states, it is likely that additional constitutional issues, including possible Commerce Clause, and Separation of Powers claims, among others may prove fatal to the Clean Power Plan.

## 4. Key Issues

### a. Cost impacts

The breadth and scope of the Clean Power Plan is unlike any other proposed regulation, and estimating its impact on utility costs and customer rates presents many challenges. The proposal is premised on giving maximum flexibility to states and therefore implementation requirements are subject to speculation based on available information. Despite EPA’s predictions, a reasoned analysis demonstrates that implementation will have significant cost impacts to utilities and their customers.

EPA’s assertion in the Regulatory Impact Analysis that the proposal will have negligible economic impacts on consumers and the economy is without substantial support. *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*, US EPA, Office of Air Quality Planning and Standards, Health & Environmental Impacts Division, Air Economics Group, Research Triangle Park, NC, June 2014 (hereinafter RIA). While EPA does acknowledge that electricity prices will rise in the short-term before the final goal must be achieved in 2030, it brushes aside the impacts on consumers and the economy by minimizing long-term costs[11] and overstating projected benefits. 79 Fed. Reg. at 34,885, 34,934-34,942; RIA at ch. ES-1. The flawed conclusion that prices will decline is based on an inaccurate cost assumptions for implementation each of the building blocks, including an assumption that implementation of energy efficiency measures in every state will cause demand to go down while relying on a corresponding hope that there will be an unlimited supply of cheap natural gas long into the future. As discussed in further detail in other sections of these comments, those projections are fundamentally flawed. *See* Sections 4.g. and 6.b (natural gas issues); 6.d. (energy efficiency). It also ignores costs which result from the action that states must take to implement the emission reductions, including stranded investments. RIA ch. ES-1.

Furthermore, the overwhelming benefits EPA touts are grossly overstated. The proposed rule and the RIA both base their analysis on the reduction of pollutants other than the $CO_2$ which is the subject of this very regulation. Tables 10, 11, 14, 15, 16, and 17 all graphically demonstrate that EPA monetizes the benefits of the proposal based on the co-benefits of reducing $PM_{2.5}$, $SO_2$, $NO_x$ and Ozone, each of which has its own National Ambient Air Quality Standard (NAAQS) that must be achieved for purposes of public health. 79 Fed. Reg. at 34,931-34,932, 34,837-34,940; RIA chs. 4, 8. Indeed, EPA itself acknowledges that it may be double-counting benefits. RIA at 4-15. Further, its analysis and inclusion of global climate benefits reaches far beyond the assessment of the regulation on the economic impact on the nation itself and the reach of its permissible regulations.

The EPA's assessment of economic impacts of the Clean Power Plan is plainly inaccurate. As noted, one of the major shortcomings is the failure of the proposal to account for the impact on utilities, consumers and the economy that result from stranded investments. The proposal anticipates (but underestimates[12]) that it will force the premature retirement of "some" coal plants, as well as a reduction in the reliance on existing coal resources by shifting generation to natural gas and renewable resources. 79 Fed. Reg. at 34,935. Premature retirement inescapably results in economic losses because useful life is properly thought of in terms of an asset's ability to yield on-going economic value, so shutting down an electric generating facility prior to the end of its useful life is sure to result in losses for someone – and ultimately the ratepayer.

The useful life represents the period over which an asset is expected to provide value to its owner. In fact, the accounting assumption as to the useful lives of assets should be based on economic and engineering studies, on experience, and on any other available information about an asset's physical and economic properties.[13] In the case of public power electric utilities, the

[11] It was Harry Hopkins, President Franklin D. Roosevelt's advisor, who first observed that "People don't eat in the long run" and that it is incumbent on policy makers to address directly the short-term as well as long-term impact of their decisions. http://www.rooseveltinstitute.org/new-roosevelt/great-depression-great-recession (last accessed November 6, 2014).

[12] The Midcontinent Independent System Operator (MISO) analysis has projected that the Clean Power Plan will force the retirement of more coal plants than EPA has predicted. MISO predicts an additional 14 GW of generation will be forced to retire. "GHG Regulation Impact Analysis – Initial Study Results," MISO, September 17, 2014 (see note 15). The Southwest Power Pool, in its preliminary reliability impact assessment found that EPA had modeled the retirement of an additional 6 GW of retirements in excess of SPP's current projections. "Reliability Impact Assessment of the EPA's Proposed Clean Power Plan," SPP, October 8, 2014 at 2 (see note 32).

[13] *Financial Statement Analysis*, Wild, Bernstein, Subramanyam (2003).

generating assets are, in effect, owned by the utility's customers, with the utility acting as their agent. So, customers bear the economic costs of ownership, but also realize the economic benefits. As long as the going-forward variable costs of producing electricity with the coal plant are less than the all-in costs (fixed and variable) of viable replacements (market purchases, or resource acquisitions), the plant will yield economic benefits for customers. If the plant ceases operation during its economically useful life, customers will suffer an economic loss from electric rates that will be higher than they would have been it if the plant continued to operate. Furthermore, the loss borne by customers will be the same irrespective of the debt service schedule.

One of the fundamental flaws of the Clean Power Plan is that EPA fails to acknowledge that forcing the premature closure of power plants that have years – and in many cases, decades – of remaining useful life creates significant costs to utilities that will be borne by consumers and the economy. The suggestion in the NODA that allowing states to "account for the book life of the original generation asset, as well as the book life of any major upgrades to the asset," (which the Integrated Planning Model sets at 40 years for new coal plants) simply does not solve the problem created by the rigid glide path that limits virtually any meaningful way for states to take into account the remaining useful life of the facility. 79 Fed. Reg. at 64,549. As a result, the suggestion in the NODA does not alleviate any concerns about the economic impact of forcing premature shut down of coal plants. MRES is just one stark example of the impact of stranded costs.

#### i. Stranded assets – Wyoming coal generation

For MRES, the Clean Power Plan is likely to be costly. Since we have only one base load resource which is a coal plant, and we have no Natural Gas Combined Cycle (NGCC) capacity, we are left with few options to reduce $CO_2$. To entirely shut down all three units at Laramie River Station would cause MRES alone an increase in wholesale power costs of 65%, and would cause our member municipal utilities on average a 20% increase in retail rates to their customer-owners. (That is not even considering what it would do to the costs for the other 5 co-owners of the plant.) If a less drastic approach were taken and only one unit at LRS were retired, it would cost MRES approximately 20% more or $35 million annually to replace the lost base load generation with lower emitting natural gas, assuming natural gas prices do not experience a rapid escalation. These costs are direct costs that would be felt by consumers in Iowa, Minnesota, North Dakota and South Dakota.

If the owners of LRS are forced to retire a unit or the entire plant, this will result in significant stranded investment. LRS has a gross book value of about $1.2 Billion, and the Western Minnesota/MRES share of that is about $200 million. Currently, LRS is under a mandate from EPA under the Regional Haze Rule to install Selective Catalytic Reduction (SCRs) on all three units at LRS. This will come at a cost of $750 million to the project owners. For MRES, its share of this cost will be approximately $125 million, which will cause an increase in wholesale rates of 10%. These investments must be made by 2019[14], a year before the start of the interim compliance period of the Clean Power Plan. If forced to retire a unit, $250 million of consumer-

[14] This date is subject to change, based on the stay granted by the 10th Circuit in the litigation over the Regional Haze Federal Implementation Plan. *See* note 1.

owned investment to meet Regional Haze rules will be stranded, on top of the economic value of the remaining useful life of the unit. Those costs will no longer be spread out over the 20-30 year remaining life of LRS, but must nonetheless be recovered from ratepayers, a cost for which they will no longer receive any value.

In addition to that, MRES must replace the lost generation from the retired unit and would presumably do so by constructing an NGCC plant. (MRES has no existing NGCC resources, which makes the application of building Block 2 completely impossible.) While this is a lower-emitting resource, it still comes with a $CO_2$ footprint. More practically, construction of an NGCC plant presents its own hurdles. The LRS plant site in particular, and Wyoming in general, lacks the necessary natural gas infrastructure to replace a lost coal unit with NGCC, not to mention the lack of electric transmission availability. Other hurdles to construction in Wyoming include limited site acquisition potential, together with the complex endangered species issues surrounding the sage grouse. MRES would then look to its member states to find a feasible site for the construction of natural gas generation (without running afoul of existing attainment issues and other permitting problems). Assuming that could be done by 2020 is an unrealistic assumption, given engineering, permitting, transmission and construction timelines. Even assuming the completion of an NGCC plant sometime in the near future, the cost to do so will also have an impact on MRES and its members. Shutting down a unit at LRS and replacing it with an NGCC plant would cause an additional increase in wholesale costs of 20%, over and above the 10% cost increase caused by the installation of the SCRs.

As a result, our member community of Pella, Iowa, which receives 100% of its power from MRES, will experience an increase in its wholesale costs of 30%. This leap in power costs comes just after we have undertaken major projects to reduce $CO_2$: Pella has retired its local coal plant and MRES is constructing a new 36 MW hydroelectric facility near Pella. This is antithetical to sound public policy to encourage the reduction of $CO_2$ in reasonable and fiscally responsible ways. Rate increases of this magnitude also endanger economic development and present a very real potential that electricity will become unaffordable for the poorest among us and make electricity more expensive for facilities in the United States and potentially cause companies to abandon plants and relocate overseas.

#### ii. Stranded assets – Iowa, Minnesota, North Dakota, Wisconsin non-emitting resources

In addition to the stranded investment in LRS and the associated costs with replacing that generation, the Clean Power Plan threatens to strand MRES contractual interests in renewable and nuclear resources. As noted previously, MRES has contracts for the output of over 117 MW of clean, non-emitting resources located in Iowa, Minnesota, North Dakota and Wisconsin. We are also in the process of constructing a 36 MW hydroelectric power plant at the Red Rock Dam in central Iowa. Together, this totals more than 153 MW of clean power that should be available to MRES for use in offsetting emissions from its only coal plant in Wyoming. However, the way the Clean Power Plan is detailed in the preamble and the technical support documents, there is no assurance that these assets will not become stranded investments.

As detailed more fully in Sections 3.c.ii, 5.b., and 6.c.iv, the proposal does not clearly acknowledge the fact that non-emitting resources are the property of the utility that owns it or has the rights to the output and environmental attributes. Under building block 3, the Clean Power Plan provides that states are free to develop state plans that give to the states themselves – not the utility owners – the right to count RE located within the state's borders or even located in another state if the RE can be said to have been built to comply with the RE policy of the first state. In addition, such plans are not ***required*** to honor the non-emitting energy or credits generated in another state. This approach threatens to strand MRES non-emitting generation and related credits. These investments have an established value under each of the respective contracts, and that value is likely to increase substantially under a regulatory regime where those resources can be used to offset $CO_2$ generation. A regulatory scheme which restricts the interstate use of this energy and credits will prevent MRES from effectively managing its resources to reduce its carbon footprint, and will strand those assets. The stranding of both coal and clean energy resources creates a direct cost impact on MRES and its member municipal utilities.

Indirect costs might be less apparent but should also be considered because they will affect the entire electric infrastructure in our region and nation. First is the lack of base load generation as hundreds of gigawatts of coal are forced to retire to meet the goals set by EPA within this rigid framework. The Midcontinent Independent System Operator (MISO) has conducted an economic-only analysis that has estimated that in its region alone, the EPA proposal will cause the retirement of an additional 14 GW of coal units within the MISO footprint. MISO "GHG Regulation Impact Analysis – Initial Study Results," September 17, 2014.[15] While natural gas is likely to be substituted – indeed the EPA plan presumes it will be substituted – for lost inexpensive coal resources, there will be a rush to gas as utilities and merchants scramble to fill the void with NGCC resources. This will cause more volatility in the price of natural gas, which will begin a never-ending trend upward as demand outstrips supply.

It will also lay bare the woefully inadequate natural gas pipeline storage and distribution infrastructure, and will expose the lack of adequate transmission. These infrastructure investments cannot be made overnight and will create a barrier to achieving 2020 interim goals as well as 2030 final goals. It has been the experience of MRES that building major transmission infrastructure is a long process, especially when multiple states are involved. MRES is a participant, along with 10 other regional utilities, in the CapX 2020 high voltage transmission expansion in Minnesota, North Dakota, South Dakota and Wisconsin. The first permit application (for the first of many certificates of need from the Minnesota Public Utilities Commission) was filed in 2007, and the last route permit was received in 2011, a four-year permitting process covering four states. Construction of the projects is underway and is expected to be completed in 2015. That means it will have taken a total of eight (8) years to move from the initial regulatory process to energizing the lines, and this for a group of projects that were reliability and wind-generator outlet driven where all of the utilities in the region backed the projects. This does not include the years of engineering and study work that led up to the plan. The CapX lines are expected to cost more than $2 Billion and cover more than 800 miles.

[15] This report can be found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140917/20140917%20PAC%20Item%2002%20GHG%20Regulation%20Impact%20Analysis%20-%20Study%20Results.pdf (last accessed on November 25, 2014).

MRES expects future demand for transmission expansion to be great under the Clean Power Plan. The sheer time and money required for the anticipated transmission build out required by countless new NGCC and renewable projects is inestimable in its own. The time and money associated with expanding the natural gas infrastructure needed to fuel these expansions is beyond substantial, and has the potential to cripple the U.S. economy and put basic electricity service beyond the reach of the poorest Americans. EPA has not included in its cost estimates the expense to build this essential infrastructure, and is a major shortcoming of its economic analysis.

Another aspect that would negatively impact on cost is the lack of fuel diversity. Assuming the result of the proposed rule is to shift away from coal permanently, base load generation will be limited to nuclear, some hydroelectric and primarily natural gas. Reactive or load-following generation will be limited mostly to natural gas which can offer quick start-up times for peak and intermittent load-following. Currently, this country is enjoying a period of low and stable natural gas prices following the increased domestic production of natural gas. However, natural gas contracts to fuel natural gas-fired electric generation are usually limited by the natural gas providers to 3 to 5 years. With the anticipated increased reliance on natural gas, there will now be a strong incentive for gas providers to negotiate for higher prices each time contracts are discussed for renewal. By increasing reliance on natural gas, the proposed rule creates a market in which many participants want the same product which will likely increase the price demanded. Also, the upper Midwest relies heavily on natural gas for winter heating, and it is also used in industrial processes such as ethanol production. Additional build-up of natural gas to support grid reliability will increase the price for the product and could decrease the availability that some parts of the nation have enjoyed in recent years.

### b. State goals unrealistic and unfair

The EPA's methodology for setting state goals for $CO_2$ emissions is flawed and results in unrealistic and unfair targets that states are mandated to achieve. The BSER scheme that EPA has developed imposes extreme $CO_2$ reduction mandates on many states, far beyond what can be realistically achieved. Whether measured in terms of the percentage reduction over the status quo or the tonnage reduction, imposing actual $CO_2$ emission goals below 1,000 lbs $CO_2$/MWh is unrealistic. EPA's methodology results in 26 states being required to meet targets below 1,000 lbs $CO_2$/MWh – as low as 215 lbs $CO_2$/MWh in Washington. 79 Fed. Reg. 34,895, Table 8. It virtually forces states to shift to entirely renewable generation to meet their electricity needs, without consideration of the specific circumstances of each individual state, the reliability of the electric grid or the cost of electricity to consumers. Such stringent target-setting is regulatory overreach, and is so disconnected from the facts that it constitutes arbitrary and capricious decision making. *See*, *e.g.*, *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, 103 S.Ct. 2856, 2866, 77 L.Ed.2d 443, 458 (1983) (agency action will be upheld only if it "articulates a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made'") (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).

For example, South Dakota, which in 2012 emitted less carbon dioxide than 46 other states,[16] was saddled with a 35% reduction requirement, bringing its target in at 741 lbs $CO_2$/MWh – in a state that has only one coal plant and one NGCC plant. The targets force extreme reductions in states where renewable energy has a long history and $CO_2$ emissions are already low. South Dakota produces 74 percent of its energy from renewables – 50 percent hydro and 24 percent wind – with only 26 percent from fossil fuels.[17] Many other states are in a similar position. It is patently unfair to force extreme reductions on states that already have low $CO_2$ emissions. Further, the Clean Air Act, § 111(d)(1)(A) states that the Administrator may establish standards of performance for any existing source of an air pollutant. In South Dakota, only two units are considered affected EGUs. Rather than looking at the actual emissions of the affected EGU, and looking at the BSER available to those particular EGUs to come up with an appropriate target, the EPA looked "outside the fence" resulting in extrapolations on renewables and energy efficiency that have little to do with the actual affected units.

The target-setting methodology is also unfair because it fails to give credit for reductions of $CO_2$ that were implemented before 2012. By ignoring effects from $CO_2$ reduction by states and utilities achieved before the baseline year, EPA erred when it performed its analysis of what is reasonably achievable in establishing BSER. Ignoring these early actions creates a higher cost of compliance and fewer alternative choices for states choosing to reduce carbon emissions prior to the implementation of the rule.

In addition, EPA has proposed the Clean Power Plan based on a rate-based $CO_2$ limit, with the option available to convert that limit to a mass-based one. It is essential that clear and concise direction be provided by EPA. Even after the release of its Rate to Mass Technical Support Document and related data files, the calculations are still confusing, and raise questions as to whether the mass-based goal is more stringent than the rate-based goal. The release of this information has been welcomed, but it was so long in coming that state agencies and the regulated community have had little time to fully analyze the information to evaluate the potential alternative mechanisms to implement and measure compliance.

Finally, in its NODA, EPA acknowledges widespread concern with the goal-setting calculations from blocks 3 and 4, and seeks comment on whether it should revise its computations. 79 Fed. Reg. at 64,547-548. Under EPA's original proposal, addition of one MWh of natural gas generation would "back off" a MWh of coal generation, as well as the emissions from that generation. However, the addition of a MWh of renewable energy or energy efficiency (blocks 3 and 4) is not assumed to "back off" generation from fossil resources. EPA is requesting comment on whether it should change the way it calculates state goals such that EPA would "back off" additional fossil generation as additional MWh of new renewable energy and energy efficiency are added to the system. Such a change will have the effect of making all state goals more stringent than they already are, and will exacerbate the inherent unfairness of the goal computations.

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[16] $CO_2$ Emissions from Fossil Fuel Combustion – Million Metric Tons $CO_2$ ($MMTCO_2$), 1990-2012, available at http://epa.gov/statelocalclimate/documents/pdf/CO2FFC_2012.pdf, (last accessed November 6, 2014).

[17] Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923), 1990-2012, available at: http://www.eia.gov/electricity/data/state/ (last accessed on November 6, 2014).

States need the flexibility to be able to develop both a rate-based or mass-based approach for the plants/utilities in their state. This allows states to take into account the individual situations of the utilities and their resources in that state. It shouldn't matter whether different approaches are applied to utilities in the state as long as states can demonstrate that the emissions achieved by their state plans would be equal to or less than a rate-based or mass-based approach set at the state level. In addition, in determine whether to pursue a multi-state approach and, if so, in developing that approach, it is important for states to understand how the different rate-based or mass-based approaches can be work in a common plan and, whether it will be workable to have both rate- and mass-based approaches in a multi-state plan.

### c. 2012 Baseline flawed; use alternative

To calculate the state goals, EPA started with the combined 2012 $CO_2$ emission rate for each state's covered fossil fuel-fired power plants. Using a single year as the starting point to calculate the rate-based goals for each compliance period fails to take into account data anomalies that can occur in any given year, and did in fact occur in 2012. For example, we have identified data anomalies in three states in which MRES serves members: Iowa, Minnesota and South Dakota, as well as an anomaly in the operation of LRS. In Iowa, the City of Pella Municipal Power Plant is identified as an affected unit, but was retired in 2013 and did not emit any tons of $CO_2$ in 2012. In Minnesota, Sherburne County Generating Station (Sherco) Unit 3 was offline for all of 2012 due to an unplanned outage, making the starting point of Minnesota's goal calculation atypical. This should be corrected, as Minnesota will continue to rely on this generating unit (approximately 900 MW) for the duration of the planning period, and likely beyond. Further, Hutchinson Plant #2 is erroneously categorized as an affected unit, even though it does not meet the criteria because its average annual operation has been below 219,000 MWh threshold. The Hutchinson unit should be removed from the list of affected units, and the goal recalculated for Minnesota.

Further, a significant forced outage at Laramie River Station in 2012 makes the selection of that single year unrepresentative of generation at LRS. The operating hours for 2012 for Unit 1 were less than 60% of normal because of a long forced outage caused by a fire. The 2012 data for LRS is not representative of normal source operations for LRS Unit 1.

In South Dakota, Deer Creek Station, the only NGCC plant in South Dakota, was modeled by EPA as operating at 1% capacity factor during 2012. However, Deer Creek should have been considered "under construction" during 2012 because it did not go into commercial operation until late in 2012 and had only 190 total run hours for the year. While firing of the unit may have begun in April, it was not commercially operated for the bulk of the year. The 1% capacity factor is clearly unrepresentative, and South Dakota was the only state that had a less than 10% NGCC capacity factor applied in EPA's building block 2 calculation. TSD: Goal Computation, Data File: Goal Computation – Appendix 1 and 2 (XLS). The proposed methodology, as it is currently applied to South Dakota, produces flawed targets that must be adjusted. For example, applying building block 2 in South Dakota under the proposed methodology results in Big Stone Plant, the state's only coal-fired EGU, having to operate at a 23% capacity factor, forcing the state's only coal unit to be offline at least half the year. This also assumes that the ability to redispatch resources under building block 2 is technically feasible as applied to South Dakota, which is incorrect, as explained later.

Finally, using a single year as the basis for the calculations is inconsistent with the way the industry operates. Electric generating units require regular maintenance and must be taken out of service for extended periods of time to complete maintenance and upgrades. For example, Laramie River Station, which is comprised of three generating units, is on a three-year maintenance schedule, with each unit being shut down for maintenance on a rotating basis. Many utilities in the industry adhere to a three-year maintenance schedule and, regardless of the specific schedule, selecting any single year is likely to fail to reflect the actual capability of the generating fleet. Additionally, variations in weather have a significant impact on not only the demand for electricity, but also the type of electricity generated in a given year. For example, the amount of fossil generation in the Upper Great Plains region is significantly affected by the amount of hydropower generation: In high water years there is more hydro and less fossil generation, and likewise in low water years, there is less hydro and more fossil generation. Averaging the baseline will tend to reduce the impact of weather anomalies as well as unit outages.

The discussion above points to the broader issue that basing state goals on a single year cannot capture all sorts of variability of outages (both planned and unplanned), fuel prices, weather, and other factors that may affect generation and emissions. In its NODA, EPA has solicited comments on whether it should consider a multi-year baseline period as the starting point for goal computation. 79 Fed. Reg. 64,553. More specifically, MRES agrees with the suggestion that the base year should be an average of three representative years, such as 2009, 2010, and 2011. Adopting this approach would take into account coal generation from the Pella Municipal Power Plant, allowing that retirement to be meaningfully reflected in the calculations, would more accurately reflect the output of LRS as well as Sherco, and could correct the issue with Deer Creek, as well as account for maintenance outage schedules and weather variations that affect generation. This will result in more accurate calculation of state goals.

### d. Timelines are unrealistic for state plan or collaborative plan development

While it might be desirable to achieve major $CO_2$ emissions reductions, and to do so in an expeditious manner, the reality is that it will take significant time to achieve if it is to be accomplished in a deliberate manner without threatening the reliability of the electric system and creating economic havoc. Although the rapid one-year schedule for this unprecedented rulemaking is excessively fast, it pales in comparison to the incredibly unreasonable one year time period that states have to develop and submit a plan, which utilities must then react to in as little as one year. Likewise, the two year time period for multi-state plans is equally irrational given the breadth of this proposal and the significant interstate conflicts it sets up.

#### i. State Plan Development

First, states should be allowed a period of five years to develop a state plan to implement the rule once it is finalized (and extend the compliance deadlines an equivalent amount of time). Other major regulations under the Clean Air Act provide a similar amount of time for a state to develop an initial compliance plan, and the scope and breadth of this rule is far more complex than rules governing Regional Haze or $SO_2$, for example. Under the proposed Clean Power Plan, states are given one year for the planning and implementation of not just a rule, but of an entire program touching on many aspects of the utility industry including, but not limited to integrated resource planning, transmission and distribution upgrades and planning, dispatch of power in regional markets, resource development and financing, reliability, power quality, load following, peak shaving, and influencing consumer behaviors (energy efficiency). 79 F. R. 34838.

State air regulating agencies have limited resources, and may be unfamiliar with important components of the proposal, such as renewable energy and energy efficiency. They are accustomed to regulating sources of pollution, and that is where their expertise lies. To now impose on air regulators the obligation of developing plans that regulate beyond the fence line demands that they be provided adequate time to marshal needed financial and human resources, hone their expertise in such areas and consult with their colleagues in other state agencies, including energy agencies and utility commissions. Just as it is essential for EPA to understand the operation of the electric industry and the economic and reliability impacts of its proposal, state air agencies must be provided ample time to develop a working knowledge of the additional subject matter beyond the fence line which they are now expected to regulate. In addition, states may need to request legislative authority to implement and secure funding for key portions of the Clean Power Plan, which may take several years to achieve. Likewise, states may in turn be required to adopt administrative rules to govern the process of state plan development or components of it, which can easily consume an entire year or more. It is essential to provide state air regulators adequate time to develop plans regarding $CO_2$ in the same way that they were provided years to develop plans for the regulation of criteria pollutants.

Even if each state prepares its own separate state plan, states will still need to cooperate and come to understandings on how to address jurisdictional issues, enforcement issues and cross-border issues. Electric customers in a single state often are served by generation, both renewable and fossil fuel-fired, that is located out-of-state. Likewise, the electric power serving those customers involves transmission that may cross several states. Before state plans may be finalized, the states must have ample time during the state plan development process to address cross border and jurisdictional issues which will have an impact on transmission, generation, enforcement and compliance. Interstate cooperation is key to the successful operation of state plans because those plans will have potentially varying impacts on utilities that operate in multiple states. Further, if multi-state plans are to be crafted among several states it demands a significant planning period, and the proposed rule fails to give sufficient time to fully address state cooperation in their plan development, as discussed below.

The proposed rule fails to provide sufficient time to develop a comprehensive state plan that meets the targets of the proposed rule. Not only is there considerable time required to develop a state program, there may be additional time required for legislative approval to authorize the agency(ies) to implement the state plan. If the EPA's proposed rule is finalized in mid-2015 as indicated, the next legislative session for Iowa, Minnesota, South Dakota and Wyoming is not until January of 2016. For North Dakota, the next legislative session is not until January of 2017. Unless the legislature calls for a special session, at tax-payer expense, the authority to enter into a multi-state agreement may not be given by the legislature(s) until well into the limited period given by the proposed rule for state plan development. Even if a state has authority to adopt a state plan under its administrative procedures act and delegated authority, it still must go through a lengthy public process to enact any such rules, again adding to the delay in the process of even presenting to EPA a plan for approval.

The National Conference of State Legislatures (NCSL) has pointed out the need for EPA to undertake an effort to work with state legislatures where new authorization or enabling legislation may be required in order to implement the Clean Power Plan. In its comments filed in this docket and posted on October 21, 2014, the NCSL said it "believes the 13 months between the expected finalization of the rule (June 2015) and the deadline for states to submit implementation plans (June 2016), is not enough time for states to make any legislative changes that may be needed in order to submit a complete SIP, given the incompatibility of EPAs proposed timeline with state legislative calendars."[18] The NCSL comments go on to point out: "More than half the state legislatures will have adjourned from their regular session before EPA releases its final rule and may not be able to begin legislatively addressing any required changes until their 2016 regular session. As a result, those states would have more in the range of six months to develop an implementation plan. In addition, four states only hold regular session every other year putting them at an even further disadvantage."

Even if a state manages to fully develop and approve a state or multi-state program within the time frame set out in the proposed rules, there are still timing issues with implementation. In many states, under blocks 3 and 4, the state will need authority to move on a renewable energy mandate or energy efficiency mandate, if it is allowed to impose such a mandate.[19] This is an even more pronounced issue with cooperative and municipal electric utilities. In Iowa, for example, the state electric utility authority body, the Iowa Utilities Board (IUB), takes its authority from chapter 476 of the Iowa Code. The IUB is not allowed to take any action that is not otherwise authorized by statute. Currently, there is no legislative authority for the IUB to implement a renewable energy mandate or an energy efficiency program on municipal utilities or cooperatives.[20] To implement a renewable mandate under a state plan, the Iowa General Assembly would need to meet and approve the passage of a mandate or otherwise grant the IUB specific authority to establish such a mandate. Also, Iowa Code § 476.6(16)(c) establishes that municipals must develop an energy efficiency plan based on cost effective programs, file their plan and implement it. There is no mandate that municipals achieve a percentage savings beyond what their own studies have shown is cost-effective. Again, in order to mandate municipal electric utilities undertake certain savings, the statute must be amended to create such

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[18] Comment submitted by Debbie Smith, Nevada Senate, President and Senator Curt Bramble, Utah Senate, President-Elect and Senator, National Conference of State Legislatures (NCSL), posted Oct. 21, 2014, available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-20676. (last accessed November 6, 2014)

[19] The Clean Power Plan does not require states to mandate renewable energy or energy efficiency targets. TSD: GHG Abatement Measures, at 4-2. Indeed, MRES proposes that states be directed to make all building blocks ***optional*** compliance mechanisms. See section VIII.f.

[20] Under Iowa Code § 476.43, the Iowa General Assembly mandated that the Investor Owned Utilities (IOUs) must implement a total of 105 MW of renewable energy into their portfolios. Under Iowa Code § 476.44(2), the IUB only has limited authority for allocation of renewables specifically mandated the Investor Owned Utilities implement a total of 105 MW of renewables into their portfolios.

a mandate or statutory authority must be granted to the IUB to regulate municipal utilities in such a manner, which would be an unprecedented move. Although MRES does not advocate for such statutory changes, in order for Iowa to make such changes, the General Assembly would have to meet to pass the appropriate mandate or IUB authorization bill. In either regard, the passage of such a bill is not guaranteed; like any legislative process, a bill needed to establish the workability for a state plan would be subject to amendments or even opposition killing the proposed bill. If the legislature fails to authorize the actions in the proposed state plan, how can the state submit the plan to the EPA for approval? Even if a state plan is approved at the EPA and the state agency seeks legislative implementation of the plan elements after EPA approval, again, there is no guarantee that the state legislature would not significantly amend the proposal or oppose the passage of the bill. In order to successfully navigate state legislative pitfalls, the timing in the proposed plan must be altered to allow more time for plan development and for implementation.

Iowa is not alone in having this potential problem. In Minnesota, the existing Integrated Resource Planning Statute, Minn. Stat. § 216B.2422 would have to be re-written and passed by the legislature reflecting the mandatory energy efficiency or renewables, again a statutory change that MRES does not support. Likewise the Minnesota renewable energy mandate, Minn. Stat. § 216B.1691 and the state energy efficiency goal, Minn. Stat. 216B.241, would also have to be revised to reflect the state plan. In North Dakota and South Dakota, the renewable energy statutes are written as goals only, and neither state has an energy efficiency mandate (although energy efficiency is defined as a renewable resource in North Dakota). NDCC §§ 49-02-28 through 49-02-34; SDCL §§ 49-34A-101 through 49-34A-105. There are no renewable or energy efficiency goals or mandates in Wyoming as well.

Also, each of these states do not impose rate regulation on municipals; which will raise the philosophical debate both at the regulatory level and at the legislative level as to whether energy efficiency mandates and renewable mandates (which impact rates) should be placed on non-rate-regulated utilities. Like Iowa, each of these states' agencies does not have the current authority to mandate energy efficiency programs or renewable energy construction by the utilities. Each of these states would have to pass some sort of authorizing language for the agency or a mandate to implement the state plan (approaches that MRES believes are unnecessary). Each state must have sufficient time for the political process to develop and debate appropriate bills that would implement any proposed state plan. Again, the proposed EPA rule does not account for the legislative action that would be necessary for the development and eventual implementation of a state plan. The proposed rule should be revised to give additional time to the planning process. The proposed rule should provide states a full five years from the date the rule is finalized to submit their state plans. In conjunction, the rule should also revise the compliance deadlines in a corresponding length of time.

#### ii. Multi-State Collaboration

Furthermore, if states wish to collaborate to develop a multi-state plan, they should be provided five-to-eight years to submit a proposed plan (and the compliance date should be extended an equivalent amount of time.) An example of the time truly needed to develop a plan among a group of states is reflected in the Regional Greenhouse Gas Initiative (RGGI) currently operated in the northeastern United States. The RGGI development began with formal discussion among various states in 2003 to develop a regional cap and trade program to address greenhouse gas emissions (carbon dioxide) from power plants. The states then announced a Memorandum of Understanding in December of 2005 and published a Model Rule in August of 2006 setting forth the recommended regulatory framework for developing regulatory and statutory proposals for the various state members. The states then began their own in-state rulemaking processes to adopt a framework for each state to participate in a regional cap and trade program. States considered and adopted regulatory rules or statutes governing a trading program, parameters for acceptable emission offset projects, and authorizing and regulating language for the auctioning of allowances. States completed their regulatory and statutory work at the end of 2008 and began a regional trading program in January of 2009. All totaled, it took five to six years for the program to go from formal planning to actual trading (which does not account for the time period during which informal discussion took place leading up to the first formal meetings in 2003).

As indicated by the experience of RGGI, two years is not sufficient time to develop such a complex plan. Another complicating matter is the fact that the RGGI states were free to develop their own methodologies to calculate carbon emission reductions and how to achieve them. With the Clean Power Plan, states have only recently been provided with the methodology and data on how to do the mass to rate calculation, and must also struggle with questions regarding how to properly calculate their baseline, and how to meet such front-loaded targets in a very short period of time. Given the RGGI experience, substantially more time to develop a state or multi-state program is needed.

Additionally, each state may have to approve legislation giving the attorney general or other agency personnel the authority to enter into negotiations on behalf of the state to enter into a Memorandum of Understanding or an Interstate Compact. As noted above, if the EPA's proposed rule is finalized in mid-2015 as planned, the next state legislative sessions are not until January or February of 2016 or even not until January of 2017, in the case of North Dakota. Unless the legislature calls for a special session, at tax-payer expense, the authority to enter into a multi-state agreement may not be given by the legislature(s) until well into the limited period given by the proposed rule for state plan development. Further, given the potential conflicts and complexity of such authorization, it might not pass in the first session in which it is introduced, further delaying the ability of states to execute a multi-state plan.

Another example of the lack of sufficient planning time in the proposed rule is the experience of the Midwest Governors Association (MGA). The MGA is a group of Midwestern states that work on a variety of policy issues that cut across the upper Midwest. State members include: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio and Wisconsin. Beginning in late 2007, members of the MGA along with the Province of Manitoba, created an advisory group to study and to make recommendations for the establishment of regional emissions reductions and for the possible design of a regional cap and trade program. The representatives of the states involved included the manufacturing industry, transportation, electric utilities, environmental representatives, and agricultural interests. MRES staff were involved in the process and served on advisory group subcommittees. The advisory group had a series of meetings over a year that resulted in recommendations. The April, 2009 recommendations were made in order for the Midwest to have regional influence on a national debate regarding a federal cap and trade. In short, the recommendations did not conclude with an actual regional or state plan, but rather, after scenario modeling, studies and discussions over a year, the end result was a list of concerns, priorities and general recommendations as to how a cap and trade program *might* be designed. No specifics and no firm plan were outlined; and several participants still had concerns over the recommendations. After more than two years of work, the MGA was still a long way from a firm plan for a regional program. As the MGA experience demonstrates, the one year time period for a state plan and two years for a regional plan given in the proposed rule are simply insufficient to contemplate and resolve all of the potential issues that will arise in the development of a workable plan that also protects power reliability and quality, as well as the economy. In its comments submitted in this docket, MISO also points to the need for more time to provide a meaningful opportunity for states and regions to work together, an outcome that might help to make implementation more cost-efficient. *See* Comment submitted in Docket ID No. EPA-HQ-OAR-2013-0602, by John R. Bear, President and CEO, Midcontinent Independent System Operator, at 5, dated Nov. 25, 2014 (MISO Comments).

There are also significant multi-state issues under the Clean Power Plan that will impact whether states will choose to collaborate on multi-state compliance plans, including cap-and-trade programs. The wide disparity among the individual state emission rate goals serves as a substantial barrier on the ability of states to work together to submit a single, coordinated multi-state plan. These drastic differences in the proposed $CO_2$ emission reductions among states are especially noticeable in certain regions of the country. For example, the percent decline in state emission rates that the proposed rule requires within the North Central region, where MRES members are located, ranges from 11% and 16% in North Dakota and Iowa to 35% and 41% in South Dakota and Minnesota, respectively. 79 Fed. Reg. at 34,895, Table 8; *see* "States would see widely different requirements under EPA's $CO_2$ rule," SNL Financial, June 2, 2014. Having such a wide disparity in the state goals discourages states, such as Iowa, from joining together to develop a multi-state plan with a state, such as Minnesota, which faces a much more stringent interim and final goal. This results in states with significantly more stringent $CO_2$ emission reduction goals being forced to look exclusively at developing their own individual state plans.

The multi-state planning process is made more difficult by the inequitable burdens that the Clean Power Plan creates among states. States with a diverse mix of generating resources within their state are not likely to partner with a state that relies substantially on affected coal-fired EGUs, lacks NGCC resources, and has poor opportunities for renewable energy development, or one which relies heavily on hydropower. There is too much uncertainty created as to whether such a state could meet its obligations under a multi-state plan if it fails to adopt all four building blocks used by EPA to represent the BSER for fossil fuel-fired power plants. Further, the proposal also pits states against one another when it provides that a state may count under building block 3 the renewable energy located out-of-state if it was constructed as a result of the state's renewable energy policy. TSD: State Plan Considerations, at 90.

Any multi-state plan that is developed will need equitable, efficient, and enforceable rules for governing the multi-state program that is to be put in place under the plan. Based on an initial review, it appears that the RGGI program would be able to meet the requirements to qualify as a multi-state program under the Clean Power Plan. However, as discussed above, the proposed rule does not provide sufficient time to establish a similar program under a multi-state plan in other regions. Based on the RGGI experience, it is unlikely that states would have sufficient time to work together to submit a single, coordinated multi-state plan that includes a similar RGGI-like program by the June 2018 deadline for multi-state plan submittals, assuming a 2-year extension is granted. The timelines for states to act that EPA has established are unrealistic and unworkable.

States must be encouraged to work together to find regional solutions. Indeed, the electric industry does not fall neatly within state borders; most utilities operate in interstate commerce, serving customers in multiple states. It would be preferable if states were given the time to coordinate (at a minimum) or to develop full-fledged multi-state plans. The best way that EPA can encourage states to do that is to provide them sufficient time to not only work out how their individual state is affected by the rule, but how their neighboring states are impacted, as well as utilities and customers throughout the region. By allowing a full eight years for the development of multi-state plans, EPA will provide the necessary incentive for genuine cooperation. The plan deadlines must be extended.

### e. State plans are a barrier to renewable energy development

The regulatory scheme developed by the Clean Power Plan creates a chilling effect on the development of new renewable energy in this country. The uncertainty surrounding the interstate use of non-emitting generation and credits has been detailed throughout these comments. *See, e.g.* Section 4.a.ii. That uncertainty will prevent not only MRES but also other utilities from constructing renewable resources because there will be no assurance that those resources can be used to achieve compliance with $CO_2$ reduction goals in the various states in which they operate.

Prior to the release of the Clean Power Plan, MRES integrated resource planning identified a number of renewable energy projects for potential development. Those included development of hydropower resources on the Mississippi River at Lock and Dam 11, Lock and Dam 15, and Melvin Price Dam. Those plans also included development of pumped hydro storage along the Missouri River, and a need for a variety of wind energy resources. Under this proposal, however, MRES is confronted by the parochial interests of states that wish to include in a state-driven portfolio plan all renewable resources located within their borders, effectively prohibiting MRES from using that non-emitting generation from offsetting its $CO_2$ emitted in Wyoming.

For example, if a state like Iowa or South Dakota, with both rich wind resources as well as potential hydropower development, adopts a state plan that requires in-state resources to remain in-state then utilities (and developers) will avoid investing in clean energy in that state because the energy and/or credits are no longer freely transferable in interstate commerce to meet the utility's unique resource planning and compliance needs. Utilities will be forced to locate such resources only in states where they emit $CO_2$ rather than focusing on where the best natural resources are located and can be built at the lowest cost. Unfortunately, in the case of MRES (as well as other utilities) the opportunities to build renewable resources in the state where emissions occur (Wyoming) may well be severely limited either from a resource standpoint or by regulatory or infrastructure barriers. *See* Section 6.c. For a state like South Dakota, with vast wind resources yet to be tapped and only two affected units, it is a death knell for further development of renewable resources if the renewable energy and credits cannot be used beyond the state borders. The failure of the Clean Power Plan to explicitly provide for the interstate portability of non-emitting generation and credits has the opposite and negative policy result of abruptly cutting off the development of renewables in the regions with the best resources.

### f. Front-loaded glide path must be changed

By setting an initial interim goal in 2020 which requires, on average, approximately 80% of the full reduction to be achieved in that year,[21] EPA denies to states any flexibility to craft a rule that will be able to take into account its unique situation, let alone the specific issues facing individual EGUs (such as remaining useful life), utilities, or ratepayers. The front-loaded glide path proposed in the rule fails to provide sufficient time to implement Blocks 2, 3 and 4 such that reductions could be made in a timely fashion to meet the interim and the final reduction mandates. This viewpoint is widely held throughout the industry, including not only utilities, but also Regional Transmission Organizations/Independent System Operators/Regional Coordinating Entities (collectively referred to as RTOs) and states. Both MISO and SPP have also called for an extension of the 2020 date for initial compliance and the associated glide path. MISO Comments, at 102; Comments of Nicholas A. Brown, President and CEO, Southwest Power Pool, at 10, dated Oct. 9, 2014, filed in Docket ID No. EPA-HQ-OAR-2013-0602 (SPP Comments). Likewise, the State of Iowa, has also advocated that the interim goal be eliminated, or at the very least, start no earlier than 2025. Joint Comments of Chuck Gipp, Director, Iowa Department of Natural Resources, Elizabeth S. Jacobs, Chair, Iowa Utilities Board and Debi V. Durham, Director, Iowa Economic Development Authority, at 5, dated Nov. 12, 2014, filed in Docket ID No. EPA-HQ-OAR-2013-0602 (State of Iowa Comments); Comments of Dennis Daugaard, Governor, State of South Dakota, and Attachment A, at A-16, dated November 25, 2014, filed in Docket ID No. EPA-HQ-OAR-2013-0602 (State of South Dakota Comments). Instead, states should be given full control over setting the interim goals for 2020-2029. Finally, as noted earlier, EPA encroaches on state sovereignty in violation of the Tenth Amendment when it devises a scheme that takes away from states the traditional authority reserved to them to regulate such matters within their own borders.

We appreciate that EPA's NODA has sought comment on the potential to alter the glide path and provide a "more gradual phase-in" of building blocks, evidencing its recognition of the widespread concern over this issue. However, EPA's response suggests accommodation primarily by permitting states to begin the glide path *earlier* which serves only to make the goals more stringent and impracticable by requiring action in an even shorter time frame. 79 Fed. Reg. at 64,548. For each state with an affected EGU, EPA mandates that states begin meeting the interim goals in 2020 and meet the targeted reduction goal for the state by 2030. Additionally, beginning in 2030, the targeted greenhouse gas emission standard must continue to be met continuously and indefinitely, regardless of growth or other outside impacts. This glide path does not allow sufficient time for the states with affected EGUs to implement and begin meeting the demands or targets of a state program. The BSER measures[22] that are to be used to achieve the interim goals of the glide path demonstrate this shortcoming.

[21] 79 F.R. 34895, Table 8. *See also* NODA, 79 Fed. Reg. at 65,546.
[22] The building blocks identified as BSER are addressed in detail below in Section 6.

First of all, as indicated throughout these comments, the ability to gain the emission reductions predicted by EPA from Block 1, is severely limited, if not impossible. Specifically, Laramie River Station has undertaken all the efficiencies it can identify. And, even if there were any additional improvements to the heat rate that could be done, the glide path does not give sufficient time to meet 2020 interim goals. Assuming a state plan is completed by 2016 and approved by the EPA in that same year, utilities and regulators are left with less than 4 years for significant planning, budgeting, permitting and financing of major enhancements to improve the heat rate before 2020. The NODA asks for input on whether allowing a phase-in of block 1 improvements will adequately address timing concerns. 79 Fed. Reg. 64,548. Planning improvements requires engineers to analyze the types of improvements, understand the impacts, and plan the plant outages for the installation of any heat rate improvements, and time for regulators to review and approve such plans. Individual state air regulators understand these limitations which face the fleet in their state because they have been regulating them for the life of the plant. While allowing a phase-in for block 1 might benefit units that have available efficiencies yet to achieve, it is unlikely to have a significant impact on the overall workability of block 1. In sum, it is very unlikely that LRS or any other affected EGU would be able to get any heat rate improvement (whether by 2020 or phased-in), leaving the states and the utilities to rely instead on Blocks 2, 3, and 4 to achieve the significant emission reductions required by the glide path in this short time frame.

As to Block 2, EPA assumes that all states and utilities with coal resources also have NGCC resources in the same state that can simply be quickly redispatched to offset coal generation by 2020; that assumption is flatly wrong.[23] NODA, 79 Fed. Reg. at 64,546. In the NODA, EPA appears to acknowledge the major timing issues associated with NGCC redispatch and has asked for comment on whether a more gradual phase-in would alleviate concerns over workability and reliability. *Id*. at 64,548-549. While the acknowledgement of stakeholder concerns is laudable, it does not resolve the basic flaws of building block 2.

First, states have no authority to mandate dispatch of NGCC within their state; the dispatch of power is governed by the RTOs. The NGCC units in existence were planned, permitted, constructed and interconnected with transmission based on the needs of the operating/owning utility, and are limited by physical pipeline and transmission constraints, permit limits and gas availability, none of which can be simply ramped up to meet the 70% assumed capacity factor by 2020. The glide path's assumption that all NGCC can be ramped up to 70% in 2020 ignores basic operational issues. The timing of the glide path does not reflect the transmission or interconnection studies, revised agreements or RTO modeling that would have to be accomplished in a very short period of time to increase the capacity factor, while still meeting reliability requirements of the North American Electric Reliability Corporation (NERC). And of course, that is predicated on the assumption that transmission capacity is available for the increase in NGCC operation. In fact, if the existing units are in a transmission constrained area, new transmission must be added to accommodate the load. Transmission studies on average take about two years to complete. That new transmission cannot be guaranteed to materialize in the time frame suggested by the proposed rules.

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[23] In fact, MRES (a relatively small municipal entity) provides a classic example of a utility that owns only one coal resource and no NGCC. Further, in the state of Wyoming, there are 10 coal-fired power plants that are affected units and only one 95 MW NGCC plant. This issue is more fully discussed below in section 6.b.

For example, the Minnesota CapX 2020 project took roughly 10 years from initial planning stages, to permitting, to the placement of the new lines into service. Also, the CapX project has taken additional time as there have been contested court challenges to eminent domain and the Minnesota "Buy the Farm" statute which requires affected agricultural land to be purchased in whole, and not just the impacted portion. *See* Minn. Stat. § 216E.12, subd. 4. As the EPA is well aware, contested case proceedings will significantly lengthen the timeframe of building needed transmission, will be a significant barrier to states meeting glide path milestones, and are an inevitable part of transmission siting in the 21st century.

Second, as to Block 2, the EPA glide path inherently assumes that redispatch can be achieved seamlessly by 2020; it entirely fails to account for the fact that NGCC is used as reactive power to back up the intermittent renewables, such as wind. If those current units are redispatched as base load, new natural gas-fired units would have to be constructed for the purpose of providing reliability for the renewable energy already on the ground. The inability to redispatch means that Block 2 – where EPA assumes over 30% of reductions can be made – is not available to MRES, nor is it even remotely possible in many states. Instead, EPA must acknowledge that the states alone are in the best position to determine when and how reductions can be made under this building block during the interim glide path period.

Finally, in the upper Midwest, where the MRES load is centered, there are already constraints in natural gas capacity. Northern Natural Gas, one of the leading suppliers of natural gas in the upper Midwest, faced constraints and limited capacity during the "polar vortex" of 2014. It may require new natural gas infrastructure just to provide additional supply to existing NGCC plants that EPA anticipates running at a higher capacity factor, not to mention what will be required for the construction of new facilities. New natural gas lines would also face the need of ample time frames to be permitted and constructed. The public notice, permitting, and construction will take years, not months. There will also be added delays if the lines are opposed, if there are environmental impact issues, or if there are eminent domain complications. Before the publication of this proposed rule, the MISO region already had 3.7 GW of announced coal retirements and 5.0 GW of new gas plants announced in the region.[24] In order to interconnect the MISO-forecasted NGCCs and simple cycle turbines, the lateral natural gas pipeline construction will cost between $870 million to $1.08 billion. This is for the construction of lateral lines only and not including any mainline costs. *Id.* at 117, Table 6-3 at 118. The rules before us would lead to even more natural gas-fired generation than the predicted 830 MW; again, adding to the complexity and the time for planning, permitting and constructing sufficient natural gas construction in the upper Midwest alone. As the MISO natural gas infrastructure analysis concluded,

> "…there must be consideration for the lead-time required for pipeline construction to meet the need of power generators by 2015/2016 and the potential for construction delays due to the anticipated increase in power generation interconnection request. Lastly,

[24] *"Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis,"* prepared for MISO by EnVision Energy Solutions, Dec. 1, 2013, at 63-64; available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Phase%20III%20Gas-Electric%20Infrastructure%20Report.pdf. (last accessed November 6, 2014)

> decision-makers must recognize the competing needs for pipeline construction as industrials and other reshoring industries ramp-up. This will affect the availability of skilled labor and materials and will most likely increase costs for those that postpone decision-making. The electric power industry must determine its own level of redundancy and reliability requirements and the means to recover costs associated with the value of reliability under its economic models.

*Id.* at 124-125 (emphasis in original). Simply put, the anticipated substantial increase in natural gas reliance and additional natural gas capacity needed makes the glide path milestones difficult, at best, to reach in the allotted time. Again, the compliance milestones should be left to the states to determine.

Yet another reason the proposed glide path schedule should be revised is that it does not anticipate the time to implement any state policy to create incentives or mandates for construction that pertain to Block 3, which represents more than 30% of the reductions the EPA plan assumes in setting state goals. "EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," The Brattle Group, at 3, Table 1 (renewable generation in building block 3 accounts for 33% of the total BSER $CO_2$ reductions in the Clean Power Plan). Although Iowa, Minnesota, North Dakota and South Dakota are leaders in wind development, that leadership role has largely been a product of the availability of abundant wind resources in the geographic region, as well as well-priced generation equipment and transmission capacity. As more renewables are added, the transmission and the distribution grid will need to be expanded, as well as updated, to reliably serve demand and to keep the grid robust. The rigid EPA glide path fails to provide for sufficient time to plan, finance, permit and construct sufficient renewable generation, as well as NGCC to support such intermittent resources (like wind and solar), electric transmission, and natural gas infrastructure. States are individually in the best position to know the practical velocity with which non-emitting resources can be constructed to ramp up to the 2030 final goal. States have the experience and expertise in these areas, and can be entrusted to develop viable glide paths that demonstrate progress toward the reasonable achievement of that goal.

In regard to block 4, the proposed rules assume that energy efficiency programs can be quickly and easily implemented, as many such programs already exist. Yet there is an underlying flaw to this conjecture: while utilities (and third parties) do implement energy efficiency programs, it is only the consumer that actually takes energy efficiency action. Simply put, utilities have no control over the actual amount of savings achieved, regardless of the incentive; only the customers do. Even in the state of Vermont, where the state centrally designs and operates the energy efficiency programs on behalf of the utilities, the state cannot mandate customer participation or investment. Also, despite the implementation of energy efficiency, demand may still grow and outstrip energy efficiency (EE) due to the introduction of new electric-fueled technology, population growth, economic development, or for countless other reasons. Further, there are other non-economic barriers to achievement of EPA's expected 1.5% annual savings, barriers which states are in the best position to assess. States have a detailed understanding of what EE has been achieved in the state already, and they are in the best position to know what will work for the utilities and consumers in their own state, including the pace at which EE ramps up and whether that is even possible, let alone economical.

Block 4 also presumes that there will be developed a consistent way of creating EE credits, perhaps in a manner like RECs associated with renewable energy or in some other manner. This will require an entirely new effort by states and stakeholders to develop a consistent system where 1 kWh saved = 1 kWh credit. This implicates the necessity for credible evaluation, measurement and verification (EM&V) measures. Some states have approved EM&V measures or Technical Resource Manuals that apply to programs within their states. EPA should provide a list of the various EM&V standards that are in place and allow states to choose from among those existing measures. This is an area ripe for state collaboration. This will leverage the complex work that has already been completed in leading states and provide an opportunity for consistent approaches to EM&V, based on the needs of each individual state. Without such an approach to EM&V alone, it will take years for individual states that haven't yet done so to develop such measures. Once EM&V has been established, it will still take significant time to develop a mechanism for creating, tracking, and retiring credits, time which is not provided in the present proposal.

In summary, the glide path would require Minnesota to achieve 84 percent of its total mandated reductions by January 1, 2020 (moving from a 2012 historical emission rate of 1,470 lb. $CO_2$/MWh to 965 lb. $CO_2$/MWh),[25] a huge feat in such a short time. Likewise, Iowa would need to achieve 61 percent of its total mandated reductions by 2020, North Dakota 67 percent, South Dakota 67 percent and Wyoming 53 percent. This would require substantial changes in the entire electric industry in the matter of less than four years. For the reasons detailed above, this is not achievable given the limitations of natural gas capacity, renewable energy intermittency, the need for more transmission, and the lack of planning and permitting time for new renewables, new pipelines or transmission, for natural gas ramp-ups at existing plants (if feasible), or for new natural gas plants.

Overall, the implementation of the four blocks making up BSER do not fit neatly into the limited time frame of implementation and compliance. Yet, the proposed rule gives the states no authority to alter the glide path if the state encounters such obstacles as a lack of natural gas capacity, lawsuits over renewable resource or transmission construction, or lack of customer investment into energy efficient equipment in their homes or businesses. These are issues that must be solved in order for the plan to move ahead at all, and they are issues that are beyond the control of the states or the utilities. The states must retain the authority and control to set milestones or compliance periods that meet what is actually achievable given the make-up of the states' electric energy use profiles, generation and transmission capacity, and the ability for the state and state utilities to transition with the least amount of negative impact on customer rates and reliability. The problems created when the proposed rule allows only one year for the development of a state plan (or two years for a multi-state plan) are only compounded when states run into the rigid and unrealistic 2020-2029 glide path. For states to fully develop and adopt a practical, well-modeled, and reliable plan, they must be empowered to control the interim targets within the interim 2020-2029 period.

[25] The state historical 2012 emissions rate is available at: http://cleanpowerplanmaps.epa.gov (last accessed on November 26, 2014). The state 2020 interim goal is listed in EPA Technical Support Document: Goal Computation, Data File: Goal Computation – Appendix 1 and 2, at Appendix 1 worksheet.

Furthermore, it is only by granting states control of the glide path that EPA can honor its pledge to allow states to consider the remaining useful life of existing power plants in their plans. *See* 79 Fed. Reg. 34,836. Section 111(d)(1)(B) of the CAA requires the Administrator to take into account remaining useful lives. EPA provides no mechanism in the Clean Power Plan to do so, and the rigid timelines and specific mandatory goals associated with them take away from the states any potential way to tailor their rules to the specific units in their state. EPA must give states the authority to develop specific and meaningful plans to ramp up compliance during the 2020-2029 glide path to meet the final goal established in 2030.

### g. Reliability threats caused by shift in generation, lack of transmission

The reliability and security of electric industry infrastructure must take precedent over political policy debates. As drafted, the proposal requires wholesale shifts in the way electricity is generated in this country and does so without regard to the need for expanded electric and natural gas transmission infrastructure. The failure of EPA to conduct meaningful and substantive consultation with NERC and FERC[26] to ensure that the Clean Power Plan can be implemented without grave threats to reliability requires that the proposal be withdrawn until such time as those rigorous studies are completed and can fully inform the rulemaking process. Further, those same reliability issues also expose significant issues of national security.

#### i. NERC reliability concerns must be addressed

As is demonstrated by the recent publication by NERC of its analysis of the Clean Power Plan, the proposal represents an unprecedented and unproven attempt to make wholesale changes to the operation of the electric infrastructure, which threatens the continued operation of the electric grid on a local, regional and national level. In its report "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review," November 2014 (hereafter "NERC

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[26] Congress has exhibited increasing concern that EPA has failed to engage in substantive and transparent consultation with FERC on matters of reliability. "Senate Energy and Natural Resources Committee Ranking Member Lisa Murkowski (R-Alaska), House Energy and Commerce Committee Chairman Fred Upton (R-MI), and Energy and Power Subcommittee Chairman Ed Whitfield (R-KY) [on November 25, 2014] wrote to Federal Energy Regulatory Commission Chairman Cheryl LaFleur seeking information regarding any consultation between FERC and the Environmental Protection Agency in the development of EPA's Clean Power Plan and other major rules impacting electric reliability. … Testimony from FERC commissioners at separate Senate and House hearings also suggests EPA did not properly consult with the commission when writing its proposed rule and ignored recommendations from the Government Accountability Office (GAO) that a formal, documented process be established among relevant federal agencies to monitor reliability challenges." "Senate and House Committee Leaders Question Agency Coordination, Seek Action to Address Grid Reliability Concerns," dated Nov. 24, 2014, available at: http://www.energy.senate.gov/public/index.cfm/republican-news?ID=6710b3a7-76ba-4476-a980-568fb8a57a15.

Further, "FERC Commissioner Tony Clark recently called for a 'much more transparent process' tied to the EPA's plan 'in relationship to how we're modeling reliability and how reliability is being taken into consideration.'" *See* Public Power Daily, Nov. 6, 2014. "Clark, who made his comments at a meeting in Washington, DC, sponsored by the Energy Bar Association, said that 'I recently read in the press clippings an EPA official said, "We are working closely with FERC on these reliability matters." And I read it and I thought, well, that's news to me.' … Clark said, 'I know [there are] staff level conversations that are going on every so often and phone calls back and forth,' but it is 'not a transparent process to me. I know it's not a transparent process to anyone in this room or anyone else in the industry.'" Public Power Daily, Nov. 26, 2014, available at: http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=42717.

Report"),[27] NERC provides a non-partisan, objective evaluation of the potential implication of the proposed environmental regulations in an effort to "inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders." *Id.* at 1. This NERC Report establishes that the EPA proposal has not undergone a rigorous reliability evaluation, and that in initiating such an assessment, there are serious and complex reliability issues that have not been addressed in the Clean Power Plan, and that it should not go into effect until those concerns have been adequately addressed and resolved.[28]

Section 215 of the FPA authorizes FERC to approve and enforce reliability standards developed by NERC and its various regional reliability entities. 16 U.S.C. § 824o. The Proposed Rule acknowledges that reliability is an issue of concern but ultimately rests on an unsupported conclusion that it provides sufficient flexibility to avoid reliability concerns. 79 Fed. Reg. at 34,836. NERC governs the reliability and security of the grid, and utilities throughout the United States (and Canada) are subject to mandatory reliability standards, with substantial penalties for violations of those standards of up to $1,000,000 per day per violation. "Sanction Guidelines of the North American Electric Reliability Corporation," Appendix 4B, § 2.16.[29] NERC is the federally-designated and widely accepted expert in the complex field of electric reliability.

The NERC Report includes an evaluation of the EPA's projections of coal plant retirements and capacity additions under existing regulations as well as with the implementation of the Clean Power Plan. It also analyzes the difference between EPA projections and those contained in NERC's Long Term Reliability Assessments (LTRA) on the various assumptions regarding the amount of coal capacity that will remain by 2025. *NERC Report*, at 17-20. It also contextualizes those projected changes in the coal fleet by evaluating transmission planning and timing constraints, along with assessments by regional RTOs. *Id*. at 20-22.

The Clean Power Plan will force the premature closure of base load plants around the country that have not been included in existing NERC case study work to evaluate the impact of such closures, jeopardizing reliable power supply for millions of Americans. Even if we assume that energy efficiency will reduce demand by 1.5% nationwide (an assumption with which MRES does not agree), that will be inadequate to fill the major void caused when hundreds of gigawatts of coal-fired power plants close. "As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. … With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks." *Id*. at 24.

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[27] NERC's report is available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf (last accessed Nov. 8, 2014).

[28] Admittedly, the Technical Support Documents include one entitled "Resource Adequacy and Reliability Analysis." Unfortunately, the report was prepared without ***substantive*** consultation with and input from either FERC or NERC.

[29] Available at: http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_4B_SanctionGuidelines_20121220.pdf (last accessed on September 24, 2014).

Even if retired coal plants are replaced with NGCC or renewable resources, those resources and the necessary transmission to support them cannot be permitted, sited and constructed in time to avoid a major shortfall in resources around the country, a concern that NERC details throughout its report. Instead, the Clean Power Plan's "analysis" "assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region." *Id*. at 20 (citing the RIA and Integrated Planning Model documentation and data). What is left is a system that lacks inertia to provide voltage support necessary to the most basic operation of the grid in entire regions of the country, such as the Southwest Power Pool (SPP), as described more fully below.

In addition, to add significant amounts of renewable resources to the grid will push it to the limits of safe operation. Wind and solar, the predominant renewables being deployed currently, are both intermittent resources which strain the system and require redundant resources to back up when they are not available. In 2008, Texas faced a near catastrophic event when it unexpectedly experienced a loss of all of its wind capacity at once when a major weather system moved through the state. Dramatic events like that will only become more common with the massive deployment of renewables contemplated by the Clean Power Plan. In such a case, fossil resources will need to be called upon to try to pick up the load and avoid a voltage collapse, causing a widespread black out.

As a second example, Wyoming has vast wind resources which it is eager to develop. Since it has no significant load to utilize those resources, high voltage transmission must be built from Wyoming across multiple states to reach its intended Nevada or California destination. Without that build-out of transmission, the renewables demanded by the Clean Power Plan lack the critical infrastructure to move forward with a currently proposed 1,000 MW wind farm. It is irresponsible to take the approach that forces utilities and others to build renewables without first ensuring the reliability of the underlying infrastructure.

One of the underlying assumptions of the proposed rule is that natural gas, renewables, and energy efficiency can each replace coal-fired generation and that each are interchangeable with the other. When it comes to reliability, the fact is that electric generation is not fungible as EPA states.[30] Utilities are required by law to supply all of the power that customers want at the exact time they want it; this is the obligation to serve which is at the heart of the regulatory compact. Utilities cannot deny power because the proposed customer usage is wasteful, or does not occur at the optimal time of day. In order to support a robust grid and to provide power at all times at varying increments, utilities need sufficient base load power to provide voltage control, reactive power and inertia. Intermittent renewable energy cannot provide voltage control or dispatchable (reactive) power. As noted earlier, in 2008 when the ERCOT system came dangerously close to experiencing a black out, the grid frequency dropped suddenly when wind production fell from more than 1,700 megawatts to 300 MW and a system emergency was declared.[31] Also, multiple

[30] EPA believes that "system operators typically have flexibility to choose among multiple EGUs when selecting where to obtain the next MWh of generation needed" and that electricity is "fungible." 79 Fed. Reg. at 34,863-64, 34,880.
[31] "Loss of wind causes Texas power grid emergency," Reuters (Feb. 27, 2008) available at: http://www.reuters.com/article/2008/02/28/us-utilities-ercot-wind-idUSN2749522920080228 (last accessed on October 7, 2014).

power suppliers fell below the amount of power they were scheduled to produce. *Id.* This created problems moving power to the west from North Texas, leading to the emergency. *Id.*

Likewise, NERC explicitly points out that an increasing reliance on natural gas poses reliability concerns when, for example, extreme weather strains demand for electricity. *Id.* at 24. At its open meeting held on October 16, 2014, FERC reviewed both Commission and industry actions relevant to Winter 2013-14 weather events. NERC reported that there were over 35,000 MW of outages due to cold weather and fuel issues; 17,700 MW of those outages were caused by frozen equipment, controls, and frozen coal. In general, firm fuel supply and transportation contracts were honored, enabling certain generator units to perform as scheduled. However, a number of generators were exposed to extremely high fuel prices and interruptible gas transportation was often unavailable. As a result, uplift costs in organized electricity markets for the month of January 2014 rivaled the total uplift incurred by the RTOs for an entire year. (PJM reported energy uplift costs greater than $500 million for January 2014.) In addition, record high natural gas price spikes drove up prices to electric end use customers—both in real-time and over the past year—as higher wholesale electric prices were passed through in retail electric rates.

With heavy reliance on intermittent renewable generation coupled with heavy reliance on natural gas, which has a limited infrastructure, the proposed rule sets up a scenario similar to what ERCOT experienced. *NERC Report*, at 24-26 ("Coal Retirements Increase Reliance on Natural Gas for Electric Power," "The Availability of Essential Reliability Services is Strained by a Changing Resource Mix," and "Increased Penetration of Distributed Energy Resources"). Therefore, before taking affect, the proposed rule and the final rule should be modeled and studied by NERC, the RTOs, and by state utility boards to simulate the impact on reliability. The modeling should include recommendations and cost estimates for infrastructure and upgrades needed to maintain high reliability and power quality, including transmission and distribution equipment upgrades and build-out, plans to meet incremental and large load growth, and build-out of transmission and natural gas infrastructure.

In addition to NERC's assessment, it is important to consider assessments conducted by RTOs. SPP has initiated its consideration of the reliability impacts of 111(d). In "SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan" dated October 8, 2014, the RTO reported on its analysis of the impact of the proposed rule.[32] Its work indicates an expected increase in thermal overloads and low voltages due to EPA's assumed retirements, and that its summer peak modeling runs were not solving under a single contingency due to an extreme lack of reactive support. *Id.* at 4, 5. It is also concerned that under the Clean Power Plan, its minimum required reserve margin of 13.6% cannot be maintained and that the reserve margin will fall to a -4.0% by 2024, as it experiences a capacity deficit of approximately 10,100 MW. *Id.* at 5-6. SPP has emphasized in its Assessment that the Clean Power Plan will require an unprecedented level of coordination and study by local, regional and national experts before it can possibly be implemented. *Id.* at 6. *See also* SPP Comments. Although MISO's initial

[32] This report can be found at: http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf (last accessed on November 25, 2014).

review focused primarily on the economic impact of the proposal,[33] it has also evaluated the issues of reliability and transmission security and has made important findings that demonstrate the failure of EPA to accurately account for the impact of its proposal on matters essential to reliability.[34] MISO has determined that the "EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS." *NERC Report*, at 21 (footnote omitted). *See also* MISO Comments.

Further, the NERC Report considers, as any responsible evaluation of reliability must, what might happen in the event that the assumptions in the proposed rules do not materialize and there is inadequate generation to serve load over the existing transmission system. NERC emphasizes the need for a "Reliability Assurance Mechanism," or a reliability "back-stop" to preserve the reliability of the Bulk Power System (BPS) and manage impending risks to the BPS. *Id*. at 22. This would be different than the limited use reliability safety valve concept utilized to address retirements caused by the Mercury and Air Toxics (MATS) rule, and would require more extensive development due to the broad reach of the impacts of this proposed rule at all levels of reliability operations. *Id*. In fact, the need to fully develop a Reliability Assurance Mechanism is a significant part of the three recommendations that conclude NERC's report. *Id.* at 27. The EPA's proposal should be withdrawn in its entirety until such time as the reliability of its proposal has been modeled, studied, simulated, and demonstrated to work as efficiently as the present system. Likewise, any re-proposed rule must include a Reliability Assurance Mechanism that meets the satisfaction of NERC, FERC and other relevant stakeholders.

### ii. National Security

As indicated above, the heavy reliance on intermittent resources and natural gas, raises serious reliability questions. With reliability concerns come national security concerns. If the grid becomes heavily reliant on natural gas, the natural gas supply as well as the pipelines themselves become targets for the disruption on our electric grid, whether by vandals or domestic or foreign terrorists. In January, 2014, a TransCanada natural gas pipeline near Winnipeg ruptured and exploded. The explosion not only affected TransCanada, but led to the precautionary closure of two nearby pipelines, resulting in the loss or severe limitation of natural gas to more than 100,000 customers in the upper Midwest.[35] Utilities responded by asking home-heating and other customers to limit natural gas consumption. Markets responded with a dramatic jump in natural gas prices.[36] In May, 2014, a natural gas line belonging to Viking Gas Transmission Co.

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[33] MISO's "GHG Regulation Impact Analysis – Initial Study Results," September 17, 2014, can be found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140917/20140917%20PAC%20Item%2002%20GHG%20Regulation%20Impact%20Analysis%20-%20Study%20Results.pdf (last accessed on November 25, 2014).

[34] See Regional State Committee meeting agenda and Clean Power Plan report at: http://www.spp.org/publications/RSC%20Agenda%20&%20Background%20082514.pdf (last accessed on September 19, 2014).

[35] "Natural gas pipeline explosion in Canada affects western Wisconsin," Milwaukee Journal Sentinel, January 27, 2014, available at: http://www.jsonline.com/blogs/business/242291841.html (last accessed October 2, 2014).

[36] "Natural gas prices jumped after TransCanada pipeline explosion," Platts, January 29, 2014, available at: http://blogs.platts.com/2014/01/29/gas-explosion/ (last accessed on October 2, 2014).

exploded, affecting customers again.[37] If those same customers were also reliant on that natural gas for electricity as well, the results would have been even worse.

The over-reliance on natural gas also creates a less-diverse generation portfolio. MRES believes that its portfolio should be diverse both in terms of geography and fuel (to the extent possible given its limited size). Losing fuel diversity can have unintended consequences for the nation as a whole, as well as specific regions of the country. The proposed rules rely heavily on natural gas for base load, reactive power, voltage support, inertia, and grid reliability. This heavy reliance on one fuel for grid stability leaves the grid and customers vulnerable to potential disasters like the gas explosions mentioned here, or the extreme cold of the 2014 Polar Vortex which caused a lack of natural gas supply for some generators as heating demands reached record levels, causing emergency conditions in PJM and ISO-NE.[38] Moreover, if a large natural gas line or several lines were intentionally targeted for disruption, the results could be catastrophic. As we saw in the August 2003 Northeast blackout, a single non-malicious incident caused a cascading affect throughout the grid knocking out power to vast numbers of people, businesses and industry.[39] A similar incident of cascading blackouts could equally result from the loss of a significant natural gas line (such as those caused by the explosions referenced above), especially if it occurs during a peak usage period.

Also, the proposed rule moves the nation away from centralized power to a more decentralized or distributed placement of generation. With a centralized generation approach, security and reliability is protected by redundancy in the system, particularly with redundancy in transmission and distribution lines. As indicated throughout these comments, transmission and distribution line construction and upgrades can face complications in routing, siting, permitting, environmental impacts, opposition, and financing. As the nation moves to a more decentralized approach, there will need to be transmission and distribution upgrades not only to support the new generation being built, but also for reliability and redundancy. If that redundancy in infrastructure is not met or delayed, it again opens the grid to a national security risk. Without sufficient redundancy, a portion of the grid may go down without the possibility of "re-routing" the power around the disrupted portion of the grid to serve customers. If a disruption is large enough, it could cause cascading power failure which is a risk not only to the health and safety of customers, but to national security.

Finally, the Department of Defense has evaluated the role of the electricity sector in national security. In its 2008 report on the subject, the Department of Defense (DoD) Science Board's Task Force on Energy Strategy concluded that

[37] "Minnesota gas pipeline explosion leaves hundreds without service," Pioneer Press, May 27, 2014, available at: http://www.twincities.com/localnews/ci_25842310/minnesota-gas-pipeline-explosion-leaves-hundreds-without-service (last accessed on October 2, 2014).

[38] "Record US natural gas demand: Polar vortex shows differences in PJM, ISO-NE," Platts, Jan. 22, 2014, available at: http://www.platts.com/news-feature/2014/naturalgas/us-demand/polar-vortex (last accessed Oct. 8, 2014).

[39] "Industry Responses Reveal Security Gaps," A Report Written by the staff of Congressman Edward J. Markey (D-MA) and Henry A. Waxman (D-CA), May 21, 2013, at 4, available at: http://democrats.energycommerce.house.gov/sites/default/files/documents/Report-Electric-Grid-Vulnerability-2013-5-21.pdf (last accessed on October 2, 2014).

> [C]ritical missions . . . are almost entirely dependent on the national transmission grid. About 85% of the energy infrastructure upon which DoD depends is commercially owned, and 99% of the electric energy DoD installations consume originates outside the fence. … In most cases, neither the grid nor on-base backup power provides sufficient reliability to ensure continuity of critical national priority functions and oversight of strategic missions in the face of a long term (several months) outage.[40]

It would be highly irresponsible for EPA to adopt the Clean Power Plan in a vacuum, disregarding the fact that significant impacts on the electric industry pose a direct threat to the most critical missions of our national defense. The failure of EPA to evaluate grid vulnerabilities that can impact defense missions, and lead to major economic ramifications, demonstrates that EPA has not adequately evaluated the reliability issues created by its proposal. Until it does so, in close collaboration with NERC and FERC, the proposal should be delayed indefinitely.

## 5. EPA's state pathways are not viable

In the TSD entitled State Plan Considerations, page 5, Section II, the EPA identifies 4 distinct pathways available for states to develop their plans to meet the goals. They are:

- Rate-based $CO_2$ emission limits applied to affected EGUs
- Mass-based $CO_2$ emission limits applied to affected EGUs
- State-driven portfolio approach, or
- Utility-driven portfolio approach.

In this way, EPA has provided states with the framework for developing plans, and requires the states to select only among this list to develop such mechanisms. This preliminary determination that states are required to make is a foundational issue that is being glossed over but has enormous implications, and demonstrates EPA's lack of insight into the implementation of the proposal. The options are a sham, and only the last one is genuinely workable.

### a. Rate-based and Mass-based $CO_2$ emission limits applied to EGUs are illusory

First, the direct emission limits (whether rate- or mass-based) are illusions. EPA acknowledges that there is no technology available that will allow direct emission limits to be effectively imposed and met by existing plants, which is why Carbon Capture and Storage (CCS) is not identified as a BSER compliance solution in the existing source rule. 79 Fed. Reg. 34,836, 34,856-857. CCS is acknowledged to be off the table, and there is no demonstrated technology that is commercially available to control $CO_2$ emissions. The suggested heat rate improvements of 4-6% are largely unobtainable because utilities have been making efficiency improvements

[40] Department of Defense, Report of the Defense Science Board Task Force on DoD Energy Strategy, More Fight – Less Fuel, at 18 (Feb. 2008), available at: http://www.acq.osd.mil/dsb/reports/ADA477619.pdf (last accessed October 2, 2014).

whenever economical and no realistic heat rate improvements exist, or because they might trigger New Source Review (NSR).[41] Further, even if the 4-6% improvement was attainable, it would be inadequate to satisfy direct emission limits required to achieve the goals set by EPA. "EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," The Brattle Group, at 3, Table 1 (building block 1 accounts for only 12% of the total BSER $CO_2$ reductions in the Clean Power Plan). Since heat rate improvements won't meet the limits and there is no technology in place to do so, the only remaining way that EGUs could meet the emission limits under either a rate-based or mass-based approach is to limit generation which, for reasons described previously in these comments, is not practically achievable if the reliability of the electric system is to remain intact[42] and is contrary to the mandate of CAA 111(d)(1)(B) to take into account remaining useful life. For these reasons, the EPA should eliminate the rate-based and mass-based $CO_2$ emission limits applied to EGUs as options for state pathways for development of compliance plans.

### b. State-driven portfolio approach is unworkable and unconstitutional

Second, the portfolio approach demonstrates EPA's lack of understanding of the electric utility industry, at least as it applies to the state-driven portfolio approach. The state-driven approach is based on a misapprehension that the fleet of generation serving any given state is both diverse and interchangeable, regardless of unit ownership or even location within different RTOs. For example, in South Dakota there is only one coal plant – Big Stone, owned by Otter Tail Power, Montana-Dakota Utility Resources, and NorthWestern Energy – and one NGCC plant – Deer Creek, owned by Basin Electric Power Cooperative. Furthermore, the Big Stone plant is located in the MISO region, while Deer Creek will (as of October 2015) be in SPP. Similarly, in Wyoming, there are 10 coal plants that qualify as "affected units" under the proposal and only one 95 MW NGCC plant, all with various and multiple owners. Wyoming is also in the position of having one unit (LRS Unit 1) located in SPP (as of October 2015), and the rest of the generation in the state tied into the western grid managed by the Western Electricity Coordinating Council in the electrically separate western interconnection. These situations present a practical barrier to redispatch which EPA has disregarded. Furthermore, because the plants do not share common ownership, EPA cannot by rule give states the right to order redispatch of separately owned facilities without violating basic legal and constitutional principles.

A state-driven portfolio approach would put the state in the position of using the building blocks to unilaterally achieve its target $CO_2$ goal. Under building block 2, where EPA achieves more than 30% of the $CO_2$ reductions on average, the state is encouraged to mandate a redispatch of coal to NGCC. *See* "EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," The Brattle Group, June 2014, page 3, Table 1 (building block 2 accounts for 31% of the total BSER $CO_2$ reductions in the Clean Power Plan). However, a state does not have the legal authority to redispatch from one set of owners' coal plant to another owner's NGCC plant. For the state to order private parties to operate their resources to meet the State's objectives would constitute a confiscation of private resources without compensation, in violation of the

[41] See discussion in Section VI.a. below for a detailed explanation of the unworkability of heat rate improvement suggestions in the Clean Power Plan.
[42] See discussion in Section IV.e., above.

Fifth Amendment's Takings Clause, as described earlier in Section III.c. And, from an electrical standpoint, because the coal and NGCC plants may be in separate RTOs, redispatch might not be effectively achieved as a practical matter. This demonstrates just one way in which the state-driven portfolio approach will not work.

The other example discussed earlier involves the Minnesota RES, as well its 1.5% Energy Efficiency (EE) goal. Both in-state and out-of-state wholesale utilities serve the load in Minnesota, and they do so with generation (both renewable and fossil) based in-state and outside of Minnesota. However, Minnesota's $CO_2$ reduction goal is based on the generation located only in the state. It would be unjust for Minnesota to count toward compliance under the Clean Power Plan all of the RE and EE used in the state by out-of-state entities. *See* TSD: State Plan Considerations, at 84, 87. For example, MRES has no generation contributing to the $CO_2$ emissions located in the state of Minnesota. It does, however, provide RE and EE based on the state's mandates. That RE and EE has been paid for by MRES members in not only MN but also IA, ND and SD,[43] and is located in Iowa, Minnesota and North Dakota. As previously established, the state of Minnesota should not be entitled to offset the emissions of its in-state EGUs with RE and EE from a utility that does not even emit any $CO_2$ in the state. To reduce emissions at an affected EGU by requiring utilities that do not own, operate, or otherwise purchase power from the EGU to invest in RE or EE flies in the face of fairness and is outside of what the Clean Air Act envisions or allows. It is tantamount to requiring utility A to purchase SCRs for utility B's generation plant for Regional Haze compliance, simply because both operate in the same state. While MRES may have an RES compliance obligation in Minnesota, that does not entitle the state of Minnesota to take the RE paid for by MRES members and their customers to meet its state $CO_2$ reduction goal. Instead, it is only fair that ratepayers get the full benefit of their investments by allowing the utility owning the RE credits to use those credits for its own benefit to offset its own $CO_2$ emissions.

Likewise, in the state of Iowa, MRES and its members are not subject to mandatory RE or specific EE goals. Here, too, MRES does not have any affected units under the Clean Power Plan located in the state. Thus, in Iowa, MRES and its members are non-emitters of $CO_2$ and it would be unjust if the state were to adopt a state portfolio approach that requires that renewable energy generated by MRES, as well as EE saved, in the state is captive to the state to achieve reductions in $CO_2$ emitted by those utilities that own EGUs that own affected units in the state. MRES and its members have just begun the construction of the Red Rock Hydroelectric Project with the goal of reducing or offsetting the MRES $CO_2$ emissions rate at LRS, not that of the state of Iowa or Minnesota or any other state. The state-driven portfolio approach establishes the framework for states to violate the Fifth Amendment by taking property of MRES and its members (RE and EE) without compensation. This pathway should also be eliminated as an option in the final rule.

[43] As a joint action municipal power agency, MRES sets its power rates based on the all-in cost of all generation, including coal, natural gas, nuclear, and renewable resources. This also includes purchase power agreements as well as construction of a new hydroelectric facility near Pella, Iowa. All members are subject to the same rate (called the S-1 rate) regardless of the state in which they are located and whether that state imposes mandates or goals. Accordingly, the cost of the renewable portfolio of MRES is shared among all member municipal utilities. All members and their customer-owners pay for these resources.

### c. Utility-driven portfolio approach is the only possible option

Instead, the only "option" of the four state approaches that can possibly work – legally and practically – is the utility-driven portfolio approach. Within each state, each utility's $CO_2$ emissions should be evaluated against the building blocks based on the ability of each utility to implement those building blocks within its own utility system. Each state plan should be structured in such a way as to require each utility which has at least one affected EGU within the state to meet the $CO_2$ emission reduction goal established for the state, either on a unit-by-unit basis or on average across its fleet within the state. This approach ensures that only those utilities responsible for the generation of $CO_2$ emissions within the state shoulder the obligation to reduce the $CO_2$ emitted in the state. If this pathway is the only option available for the development of state plans, it will also ensure that all affected units in the United States are subjected to a $CO_2$ reduction requirement, and no unit will slip through the cracks or be subjected to a "double regulation" if states take differing approaches to development of their plans. Indeed, unless the utility-portfolio driven approach is adopted as the only compliance pathway, utilities may be subjected to conflicting and duplicative reduction requirements imposed when the multiple states in which they operate choose different pathways that may impose a reduction obligation on an EGU in one state, and on the state-portfolio approach in another.

For example, if MRES' only coal resource, the Laramie River Station, is subjected to a utility-driven portfolio approach by the state of Wyoming requiring this source to reduce its $CO_2$ emissions, it would be duplicative for the state of Iowa, for example, to take a state-driven portfolio approach which would not only impose a $CO_2$ reduction goal on MRES in a state where it has no affected EGU, but it would also require MRES and its member-owners to achieve renewable energy and energy efficiency goals to meet the state's $CO_2$ reduction target by virtue of the fact that MRES serves load in Iowa with generation from LRS. That LRS coal-generated power is thus required to reduce its $CO_2$ emissions from the source of the generation for Wyoming but also to reduce $CO_2$ for a second time to meet Iowa's goal – and potentially a third, fourth, and fifth time if Minnesota, North Dakota and South Dakota follow Iowa's approach. This will be fundamentally unfair and would cause MRES wholesale rates to its member municipalities to increase unnecessarily to cover the duplicative costs.

Similarly, if Wyoming adopts the utility-driven portfolio approach and Minnesota imposed both its RES mandate as well as a $CO_2$ reduction mandate, MRES and its members will be doubly injured. The Minnesota RES was adopted in large part as a way to offset the fossil emissions from electricity generated in other states but used by retail customers within the state. Since Minnesota was without authority to order changes to generation located outside its borders, it adopted the RES to address greenhouse gas emissions. *See* Minn. Stat.§ 216B.1691. The RES is an important tool in the state's overall $CO_2$ reduction goals of Minn. Stat. Ch. 216H. If the state now, under the Clean Power Plan, adopts a state-driven portfolio approach which in any way requires MRES and its member utilities and their customers to further reduce $CO_2$ emissions, it will double the $CO_2$ emission reduction requirements in Minnesota *on top of* the fact that MRES has already reduced the $CO_2$ from its only coal plant by complying with Wyoming's goal. Because the generation is regulated at the source of the emissions, the electricity that is transmitted into Minnesota to serve MRES load has already been subjected to a significant reduction and should not be re-regulated in Minnesota merely because it is generated out of state.

Furthermore, the utility-driven portfolio approach allows the wholesale generator to use its entire portfolio to meet its reduction/offset obligations associated with the $CO_2$ it actually produces. Under this approach, utilities would be entitled to use all of their renewable energy resources – regardless of the location of the resource – to offset the $CO_2$ they are responsible for emitting. Just as is the case today, the property interest of the utility in its renewable and non-emitting resources and any RECs or other attributes that are associated with them, as well as the savings associated with EE, remains under the control of the utility, and it gets to choose when and where it will use its RE/RECs and EE to meet a regulatory requirement. In that way, the utility-driven portfolio approach avoids the constitutional entanglements that are presented if the states are allowed to use a pathway that confiscates renewable energy and interferes with contracts. Likewise, in the event that a utility has excess credits, those should also be honored as the property of the utility and available for it to use toward compliance in another state or in another year within the 3-year compliance window. This approach prevents the stranding of non-emitting assets. Any other outcome runs afoul of the constitutional prohibition against taking private property without just compensation.

Another benefit of the utility-driven approach is that it respects the existing process by which utilities plan for resources. Utilities have established integrated resource planning methodologies which are highly complex, and take into account innumerable variables, including both cost and environmental requirements. States and the governing bodies of consumer-owned utilities can exercise their rightful authority to impose specific regulatory requirements for resource planning,[44] and those are multi-year processes subject to statutory mandates and administrative rules, to ensure that utilities are adequately balancing the obligation to serve the customer and provide cost-effective electricity with the need to observe state and federal laws and regulations, as well as regional transmission operator constraints. This is an extensive process and requires a complex balance of competing interests and technology. Only the utility-driven approach allows the utility to make its own decisions, in concert with regulators where required, on how best to achieve its $CO_2$ reductions without jeopardizing reliability or affordability. A utility-driven approach which allows utilities the option to use any of the building blocks (and perhaps other measures approved by the state) to achieve the $CO_2$ reduction goal for the state in which its EGU(s) are located, and does not impose unworkable mandates, will provide the industry with the necessary tools that it currently uses to do responsible integrated resource planning.

In addition, the utility-driven portfolio approach when applied as envisioned here also ensures that within any given state, utilities are treated similarly, regardless of whether they are investor-owned, cooperative, or municipally-owned. This approach creates an even playing field because each utility with affected EGUs within the state is responsible only for its own $CO_2$ emissions and it is not obligated to offset emissions of a utility which might have a significantly larger emission profile within the state. For example, in Wyoming where LRS is located, the utility owners of LRS would be obligated (under the utility-driven approach) to offset its $CO_2$ emission

[44] While MRES is not rate-regulated by the states in which it operates, it does file its integrated resource plan (IRP) with the State of Minnesota for advisory purposes. *See* Minn. Stat. § 216B.2422. MRES also provides a copy of its IRP to the utility regulatory bodies in each of the other states in which it has members.

rate which is above the average for the state as a whole. That means that utilities with more efficient units aren't saddled with a higher reduction due to the averaging that a state-wide approach would impose. It also means that all EGUs are treated similarly, regardless of their ownership structure.

While the proposed rule appears to have crafted multiple compliance pathways in an effort to provide maximum flexibility to states in developing compliance plans, that attempt at flexibility is misplaced, unworkable, and potentially unconstitutional. The first three pathways are not viable as a practical matter or a legal matter, and they should be withdrawn from the final rule. EPA should include in its final rule only the utility-driven portfolio approach as a mechanism within which states may craft their compliance plans.

## 6. Building Blocks are problematic

As it explains in the preamble, EPA reaches the various state goals for $CO_2$ reduction by applying a series of building blocks to the 2012 generation mix in each state, using a series of assumptions, and reaching a computation that establishes the standard that each state much achieve by 2030. Flaws in the assumptions inherent in each building block necessarily affect that calculation, resulting in skewed goals. Further, EPA also suggests that the states use the building blocks as compliance mechanisms to achieve those same goals, based again on the flawed assumptions. EPA must address the problems identified in each of the building blocks if the goals are to be accurate and compliance is to be achieved.

### a. Block 1: Heat rate improvements of this magnitude are impossible

The EPA's fundamental assumption in block 1 is that every fossil power plant – especially every coal plant – is capable of achieving an additional 4%-6% heat rate improvement. Indeed, its calculations on which it imposes the goals established by the Clean Power Plan assume that across the board, all fossil-fueled power plants will achieve a 4%-6% heat rate reduction. This assumption is wrong.

LRS is consistently operated as efficiently as possible. As consumer-owned utilities, the co-owners are motivated to optimize efficiency as a matter of sound economic business principles, and are not required to wait on approval from a state regulatory commission to undertake such projects. In recent years, the owners of LRS have taken significant steps to improve the heat rate, including the following projects, along with the noted improvement in heat rate:

- Turbine upgrades, 200 Btu/kWh
- Hydrojet installation to clean the boiler walls, 40 Btu/kWh
- Installation of an intelligent soot blowing program, 20 Btu/kWh
- CO monitors / combustion optimizer, 25 Btu/kWh

In addition, LRS has a deliberate maintenance program to ensure that the heat rate is maintained and does not degrade more rapidly than normal. Other significant maintenance activities to maintain the heat rate include:

- Condenser wall repairs
- Cooling tower maintenance
- Condenser Air in leakage testing and repairs
- Ductwork repairs
- Pulverizer maintenance (Babcock & Wilcox assured stock program)
- Feedwater heater replacements
- Steam trap surveys and maintenance
- Condensate subcooler replacements
- Compressed air system leakage surveys and maintenance

Taken together, these efforts have improved the overall efficiency about three percent (3%). They also demonstrate an ongoing effort to operate LRS as efficiently as economically possible, a practice that is undertaken consistently by the industry in general. Further, discussions with states in the region also indicate that it appears EPA's best practices have already been implemented by a majority of coal-fired power plants in Region 8, providing further proof that this building block is unrealistic.

Attempts to reduce the heat rate further are contrary to sound engineering and other principles. If LRS undertook efforts suggested by EPA to further reduce its heat rate, it could experience a loss of efficiency, which would be counterproductive and increase operating costs. In addition, the owners are acutely aware that any potential project could subject the plant to the lengthy, costly and uncertain regulatory process of NSR (whether for $CO_2$, $SO_2$ or other criteria pollutants) or cause LRS to be exposed to modified or reconstructed plant issues, depending on the nature of the improvement. The Clean Power Plan does not include an exemption from NSR requirements for improvements designed to achieve the alleged available heat rate improvements that EPA touts in building block 1. Instead, EPA merely asserts that it expects there will be "few instances" where "an NSR permit would be required." 79 Fed. Reg. at 34,859. Such platitudes provide no protection from citizen suits or from EPA's own significant NSR enforcement initiatives of the recent past.

Forcing changes in the operation of coal plants, especially retirements of coal units, will create stranded costs. For LRS, because there is no practical way to reduce the heat rate under building block 1, the only option remaining at the source is a drastic one: the owners are faced with the requirement to run the plant less or shut down one or more units entirely. The first option, running the plant less, will reduce the efficiency of the plant (and the heat rate, contrary to EPA's objective) and cause an increase in the operating costs, wholesale cost increases that will have to be passed on to our members and their customer-owners. Further, as EPA itself acknowledges, if coal plants such as LRS are dispatched as load-following units, they will have higher heat rates when operated in this fashion and during periods of startup and shutdown. TSD: GHG Abatement Measures, at 2-30. It is unlikely, however, that simply running the plant less will be sufficient to meet the $CO_2$ emission reduction required of LRS, whether under the rate-based or mass-based approach. If, instead, the owners are forced to shut down a unit prematurely, it will cause significant stranded costs and will run afoul of the directive of 111(d) to take into account remaining useful life, an express statutory mandate. CAA 111(d)(1)(B).

In any event, the Regional Haze Rule imposes additional technology requirements for LRS which have a significant parasitic load. It will require 22.5 MW of station power to operate the SCRs that have been mandated by EPA's Regional Haze Federal Implementation Plan. This will significantly reduce the efficiency of the plant, which starkly contrasts with the Clean Power Plan's assumption that LRS can achieve additional efficiencies of 4-6%. Thus, not only is LRS unable to achieve the efficiencies presumed by EPA because it has already undertaken efficiency projects, but it will actually see its efficiency further reduced because it is forced by EPA to install additional pollution control equipment. This again demonstrates a major misalignment of EPA objectives and state goals and the specifics of the EPA mandates.

Therefore, all states with affected EGUs should have their goals recalculated to accurately reflect the lack of availability of heat rate enhancements. It is irresponsible to assign mandates that are based on impossible engineering feats and unattainable emission reductions.

### b. Block 2: Redispatch not possible

Block 2 of the proposed rule is based on the flawed assumption that utilities and states may meet the targets by redispatching existing NGCC to off-set coal. Unfortunately, the proposed rule makes its calculations and resulting emission reduction goals based on the assumption that utilities owning and/or operating an affected EGU would have sufficient NGCC capacity to offset its emissions from coal-fired facilities in the same state. However, reality is that the owners of the affected EGUs are not the owners of available NGCC units. For example, MRES is a co-owner of LRS, located near Wheatland, Wyoming. MRES does not own any NGCC in Wyoming to offset its emissions or otherwise decrease the run-time of LRS. Not only does MRES not own any NGCC in Wyoming, it does not own or operate *any* NGCC. This puts MRES at an immediate disadvantage as it cannot look to Block 2 for decreasing emissions, particularly in 2020 when 80% of reductions are to be achieved, or in meeting the proposed milestones of the glide path.

In order to meet the targets based on the NGCC redispatch, MRES would have to contract for the output of, or purchase outright, an existing NGCC unit. In the preamble, EPA expressly states that its proposal does not contemplate the use of new NGCC (which would be subject to CAA § 111(b)) to offset $CO_2$ under the existing source rule because it would be more costly than existing NGCC utilization. 79 Fed. Reg. 34876. Getting a new contract for NGCC capacity is fraught with obstacles, not the least of which is the significant increase in the value of and demand for existing NGCC caused by this proposal. Even if it were possible to purchase existing NGCC capacity, it would nonetheless face the same obstacles as building new capacity as it relates to the need for more natural gas, more natural gas infrastructure, and more electric transmission capacity. Also, MRES cannot simply purchase NGCC output in a vacuum; purchase will depend on the location of the NGCC unit in relation to MRES load, the RTO in which the NGCC unit is located and whether transmission wheeling in relation to MRES load is available. The redispatch also assumes availability of the existing NGCC units to "ramp-up" operation. Existing NGCC units were permitted, designed and built based upon existing natural gas availability and transmission. A ramp-up may not be allowed because the unit was permitted at 40 % capacity. Likewise, a ramp-up may not be attainable because of existing transmission constraints. Finally, a ramp-up may not be attainable without violating other air quality rules (*e.g*. CSAPR, CAIR).

The challenges for building new NGCC capacity cannot be ignored simply because it wasn't identified as BSER by EPA in its original proposal. In the NODA, EPA appears to be taking comment more generally on whether it should treat new NGCC and co-firing as BSER for all states (even those with substantial existing NGCC capacity). It is taking comment on an option that would set a minimum utilization of natural gas in all states, and would assume that states that are below that minimum utilization would either build new NGCC to facilitate additional redispatch or would co-fire gas at existing coal-fired boilers (presumably, with any plant modifications that might be required to do so). 79 Fed. Reg. 64,549. As noted elsewhere, LRS does not have available infrastructure to co-fire with natural gas, and there are likely many other coal-fired utilities that are similarly situated. The idea that co-firing could resolve the greater issue is flawed, and it does nothing to resolve the inherent infrastructure limitations. If EPA takes any of these approaches, goals for many states would become more stringent.

MISO alone predicts that 14 GW of coal capacity will be forced to retired by the Clean Power Plan and, regardless whether it can be used for compliance purposes, utilities will turn to new NGCC to make up the shortfall in base load generation and ancillary resources. MISO "*GHG Regulation Impact Analysis – Initial Study Results*," September 17, 2014. If so, MRES must then consider whether it builds new NGCC to meet the mandates of the proposed rule, and this is where the NODA's suggestion to allow new NGCC to be used in block 2 is revealed to be equally unworkable. First of all, MRES must evaluate whether to build NGCC in Wyoming, where the affected EGU is located or build in one of the four states in which its load is located (Iowa, Minnesota, North Dakota, and South Dakota). If MRES/Western Minnesota were to build in Wyoming, it would have the benefit of having an NGCC unit in the same state as the affected EGU, however it would be nowhere near the load. Additionally, there is no natural gas infrastructure located at LRS, so it would present additional obstacles in land acquisition and siting. A new NGCC plant in Wyoming would require transmission studies, sufficient transmission capacity, pipeline capacity, dispatching power into one RTO to serve load in another RTO, and present other operational issues. Also, Wyoming lacks sufficient transmission capacity or natural gas capacity to support new NGCC. MRES would be heavily reliant on other entities to develop and build sufficient natural gas infrastructure to serve the state of Wyoming and new generation there. MRES would also be forced to rely on other transmission investors to provide for sufficient build-up of transmission to support the capacity the new NGCC plant brings to the grid. The assumptions used by the EPA fail to consider these infrastructure and RTO dispatch issues.

Wyoming also provides an obstacle on the regulatory front for adding new transmission or pipeline capacity — federal lands. The federal government owns about 48.2% of the land in the state of Wyoming.[45] As such, any pipelines or transmission lines that cross the federal lands must comply with the National Environmental Policy Act (NEPA). *See* 42 U.S.C. §§4321-4370h. The NEPA process requires filing of a lengthy Notice of Intent, followed by public

[45] "Federal Land Ownership: Overview and Data," Congressional Research Service (February 8, 2012), Table 1, Federal Land by State, at 4-5. Report is available on line at: http://fas.org/sgp/crs/misc/R42346.pdf (last accessed October 1, 2014).

comment period and scoping process. Then the project submits a draft Environmental Impact Statement (EIS) which includes the proposed action and the alternatives which is followed by agency and public review and comment. This is followed by the Final EIS and the Notice of Availability, with publication in the Federal Register. Depending on the length of a transmission line or pipeline, and depending on the impact, this process could last for years. There is also the possibility that a proposed line, much like the proposed Keystone XL pipeline, may be delayed in court battles or contested hearings regarding the impact to both federal and state lands. Again, the EPA's assumptions regarding NGCC dispatch did not adequately take into account the lack of natural gas infrastructure in the states or the timeline and process it would take to build sufficient pipeline capacity to make the EPA assumptions correct.

If, for example, MRES/Western Minnesota builds NGCC in Iowa, closer to its load, other issues arise under the proposed rule (assuming, for the sake of argument, that new NGCC can be used under building block 2). First, it is unclear from the rule whether MRES could credit the operation of natural gas in Iowa to offset the emissions occurring from its affected EGU in Wyoming. The heavy reliance on state plans without clear guidance from the EPA means that MRES could end up in a situation in which Wyoming's state plan will not count the operation of an NGCC plant in Iowa to offset a Wyoming EGU. The proposed plan and the assumptions before us fail to address cross-border issues, such as the interstate transfer of renewable energy and energy efficiency credits by the owner of the generation or energy savings. Given the length of time to plan and build very costly generation and transmission, the Clean Power Plan must sufficiently address this cross-border issue and the targets must be adjusted to account for the timing, cost and build-out of natural gas infrastructure.

Also, if MRES/Western Minnesota were to build NGCC in Iowa or another state with MRES member load, the RTO issue again arises. Our affected EGU would be in one RTO and the NGCC and load in another. Again, the proposed rule gives no guidance on how the utilities or the RTO must deal with dispatching power from a generator in one RTO to reduce emissions of an EGU in another RTO. Currently, RTO dispatch is focused on providing sufficient power to meet load reliably, to meet load fluctuations that occur due to demand or due to variability in certain renewable generation, and to provide sufficient power to support the stability and operation of the transmission and distribution grid. RTOs have not been taxed with also dispatching power in one RTO to offset emissions from an EGU in another.

Again, if MRES were to build in one of the states where it has load, it would be faced with similar infrastructure issues like those if it built in Wyoming. MISO has commissioned several studies on the impact of additional natural gas reliance for the generation of electricity in its footprint. According to MISO, it expects roughly 830 MW of new natural gas-fired electric generation by 2016. The MISO Gas and Electric Infrastructure Interdependency Analysis, dated February 22, 2012,[46] demonstrates that new natural gas pipelines will cost $870 million to $1.1 billion, based on given estimates of new natural gas. This cost estimate is for lateral pipeline

[46] This report can be found at: https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Natural%20Gas-Electric%20Infrastructure%20Interdependency%20Analysis_022212_Final%20Public.pdf (last accessed on November 26, 2014).

development only and does not include mainline construction costs. Again, like the NEPA issues in Wyoming, pipelines in Iowa, Minnesota, North Dakota and South Dakota will not be built overnight and sufficient time needs to be given to plan and build sufficient pipelines to supply the new NGCC units. The construction of any natural gas line or extension may face opposition or delays that could increase costs or require additional time for permitting, much less construction. Also, the cost associated with the build out of sufficient natural gas infrastructure must be considered in the cost assessment of the BSER in the proposed rule.

All of these obstacles exist not in isolation, but throughout the region and the nation. It would not eliminate these barriers to simply suggest that a regional approach to block 2 could smooth out the differences between states and suddenly resolve all of the structural barriers to redispatch of existing NGCC or construction of new NGCC. The attempt of EPA to suggest that region-wide compliance with block 2 could resolve the problems inherent in its proposal falls flat. 79 Fed. Reg. 64,550. This suggestion in the NODA has no merit.

Additionally, new NGCC units require additional electric transmission, which requires substantial time. An example of this is the Minnesota CapX 2020 project which is the largest expansion of the high voltage transmission line in the region in over three decades, mentioned earlier. The Certificate of Need (CON) application for the three 345 kV lines was filed with the Minnesota Public Utilities Commission in August 2007; it was granted in May 2009. A CON application was filed for the Bemidji-Grand Rapids 230 kV project in March 2008; it was granted in July 2009. Then the Minnesota Route Permit applications were filed from July 2008 to January 19, 2010; route recommendations and approval were granted from November 2010 to June 10, 2011. In the South Dakota portion of the project, a Facility Permit was filed November 22, 2010 with the South Dakota Public Utilities Commission and was granted June 14, 2011. For the North Dakota portion, a joint Certificate of Corridor Compatibility and Route Permit application was filed October 3, 2011 with the North Dakota Public Service Commission for the Fargo-St. Cloud portion of the project. Finally, a Certificate of Public Convenience and Necessity was filed January 3, 2011 with the Public Service Commission of Wisconsin for the Hampton-Rochester-La Crosse project.

These dates demonstrate the significant amount of time that it takes to receive approval of the need for and routing of transmission lines. In this case, CapX initiated the Minnesota regulatory proceedings in 2007 and the last approval was received in 2011. The construction of the lines will span the years 2011 through 2015. That means it will have taken a total of eight (8) years to move from the initial regulatory process to energizing the lines, and this for a group of projects that were reliability and wind-generator outlet driven where all of the utilities in the region backed the project. As previously discussed, a further complication in the upper Midwest is Minnesota's "Buy the Farm" law which requires that when utilities cross agricultural land, the utility must buy the entire tract of land if the farmer wants out of the land. This cost adds further costs onto to the typical $1.5 million to $2 million per mile investment in a transmission line. Again, the assumptions in the block 2 analysis fail to take into account the time, the cost, and the amount of infrastructure needed to be built to continue to meet the reliability demands of the utilities and the customers.

Furthermore, for those with existing NGCC, EPA's assumption that those facilities can ramp up to 70% capacity factor without adversely affecting the electric system is another example of a fundamental misunderstanding of the way the industry works. First, increased operation of the plants could have practical implications, including permitting issues, engineering and design limitations, natural gas pipeline restrictions, availability and price volatility, and transmission limitations. Furthermore, in the West North Central region where wind is the predominant source of renewable energy, those wind units are backed up by the existing NGCC plants. It will require overbuilding of NGCC to ensure that adequate capacity is dedicated to support renewable energy. Redispatch of NGCC resources may also interfere with NERC compliance requirements regarding capacity reserves, spinning reserves and similar requirements.

The proposed rules state that 10% of the NGCC fleet operated at 70% of capacity. 79 Fed. Reg. 34,863. Also noted in the proposed rule is that 16% of the fleet operated at 70% capacity or above in the winter of 2012 and 19% operated at 70% or above in the summer. Based on common usage in the electric industry, this clearly indicates that those units operating at 70% or above are doing so during peak periods. To make the leap that limited operation at the 70% level means that the same unit is capable of running at 70% for much longer periods of time is fool-hardy.

As noted, NGCC is used primarily to provide peaking power or to provide reactive power to back up intermittent renewable generation. When these facilities were constructed, the process involved state construction permits as well as RTO interconnection studies. When a unit is designed for peaking or load-following at a capacity factor below 70%, the transmission interconnection and transmission agreements reflect that capacity. Likewise, if a unit was constructed to run at 70% of capacity for winter or summer peak periods, that also would have been reflected in transmission wheeling agreements or interconnection agreements.

One of the biggest impacts of block 2 is that it means shutting down or reducing coal-fired generation. Shutting down coal-fired plants, particularly in the short period of time allowed by the glide path and the interim goals, means that there is less base load on the grid to provide vital ancillary services. As indicated above, it is assumed that given the short time for compliance, it will force more reliance on and build-out of NGCC. As MRES has stated in some detail (in Section IV), the decrease in diversity is also a decrease in reliability, as well as a possible national security issue. Also, the reliance on significant increases in intermittent renewables coupled with competing natural gas uses (peaking, base load, voltage support, harmonics, and dispatchable power, not to mention winter heating) puts the robustness and stability of the grid at risk.

Also, the assumption of simply operating coal less is not necessarily efficient or practical. Unlike most NGCC units, coal units don't use the fuel to operate the turbines that produce the electricity. Rather, coal units use the coal to super-heat water to create steam which is then used to operate the turbines and produce electricity. Large conversions of water to steam cannot vary quickly throughout the day or "back-off" when a certain emissions limitation is reached. This complex process requires planning a significant fuel to steam conversion, for a significant amount of power, for an extended period of time. The complex process to bring the water to the appropriate level of steam for production is the same process whether the plant is to operate for the next 25 hours or the next 2500 hours. The direction to simply operate a coal-fired plant less, means that the plant would incur the same costs, start-up time and wear and tear for less generation output as it would if it ran at full capacity. This means a higher cost to operate the plant and a less efficient use of the plant (*i.e.*, a lower heat rate). Also, if a plant is operating at a lower capacity than what it was constructed for, it is not running at optimal capability and is therefore not recovering the cost to construct, operate, and maintain it. These costs then become stranded; and for customer-owned utilities like municipals and cooperatives, the stranded costs become an additional and direct expense for the rate-payer.

The proposed rule states that "…the U.S. economy depends on this sector [electric energy] for a reliable supply of power at a reasonable cost." 79 Fed. Reg. at 34,844. The quick shift to natural gas, coupled with intermittent resources, puts that reliability at risk by failing to have sufficient time frames for transmission, generation, and gas infrastructure build-out. It also threatens reliability by shifting away from coal to heavy reliance on gas without significant modeling and infrastructure build-out or planning which puts the grid at risk. In order to maintain even minimal reliability, the rule pushes utilities and states to look beyond what may constitute "reasonable cost," to invest quickly in expensive transmission and natural gas infrastructure and the quick build-up on additional NGCC to meet peak, base load, voltage support, renewable support and dispatchable reserve resource demands.

As noted, building block 2 is simply not attainable at all because MRES does not have any existing NGCC plants to which it could redispatch its coal generation. This is a significant concern because the Clean Power Plan relies heavily on building block 2 to attain almost one-third of the reductions that are used to set state goals. This reliance on redispatch makes it impossible to achieve the reductions mandated in the state goals.

The state goals should be recalculated to accurately reflect the limitations on NGCC redispatch and build up in each state. In the alternative, states should be directed to set emission reduction goals for the affected EGUs in their state that would reflect whether redispatch or build-out is available.

### c. Block 3: Utility ownership and interstate issues

Building block 3 of the proposed rule involves the replacement of generation at affected fossil fuel-fired EGUs with zero-carbon generation (*i.e*. renewable energy generation and existing "at risk" and under construction nuclear capacity). The Clean Power Plan raises a number of issues under building block 3, such as what types of generation will receive credit as renewable resources, whether ratepayers who have paid for renewable energy resources are able to claim those resources to offset $CO_2$ emissions from their affected EGUs located in other states, and how renewable energy will be developed within the time constraints set forth in the proposed rule given the barriers to mass construction of new renewable resources.[47]

[47] The NODA invites comment on whether renewable energy goals should be reapportioned among the states on a regional basis. 79 Fed. Reg. 64,551. This new option would evaluate RE potential on a regional basis using technical and economic variables (similar to the state-by-state "Alternative RE Approach" EPA previously proposed). EPA would then allocate responsibility for obtaining the projected regional level of RE to individual states based on some criterion such as each state's share of regional retail sales or regional generation. It appears that EPA is proposing this option to address the legal risks of the current approaches for setting the RE building block used for computing each state's goal. It is unclear to MRES what effect this change would have on state

### i. New hydropower

What counts as renewable energy for purposes of compliance is a significant issue given that a large portion of the $CO_2$ emission reductions under EPA's goal-setting methodology come from the renewable assumptions under building block 3. EPA must ensure that all non-emitting energy resources, including new hydroelectric generation, are treated equally as compliance options under the Clean Power Plan. As the proposed rule relates to new hydropower, it allows states to consider generation from new hydroelectric renewable energy facilities (or incremental hydropower generation at existing facilities) as an option for compliance with state goals. 79 Fed. Reg. 34,867. Although states have discretion to count both new hydropower installations and incremental capacity increases at existing dams, the rule doesn't ensure that states must treat this new hydropower the same as other renewable resources, such as wind and solar, regardless of the size of the facility or incremental increase. This issue is of particular significance to MRES.

MRES/Western Minnesota are in the process of constructing a 36 MW hydroelectric generating facility at the Red Rock Reservoir in central Iowa. The Red Rock Hydroelectric Project (RRHP) officially broke ground on August 13, 2014, and is expected to be completed in 2018. This new non-emitting resource must be included in the list of renewable resources that may be used to offset $CO_2$ emissions. Treating hydropower differently places it at a considerable competitive disadvantage with other renewable energy resources and ignores the significant carbon emissions savings that this resource has generated – and will continue to generate – over time. Hydropower as a renewable resource is especially important because, unlike intermittent resources such as wind and solar, hydro is capable of providing base load power and ancillary services which are essential to the stable operation of the grid.

The EPA must alter its negative stance toward hydropower, as evidenced by comments in its Technical Support Document which presumes there will be no development of new hydro. TSD: GHG Abatement Measures, at 4-5. In President Obama's Climate speeches in both 2013 and 2014, he spoke about the vast untapped potential that exists at non-powered federal dams, and encouraged the electric industry to take advantage of this clean, non-emitting and renewable resource.[48] The President even placed this project on the federal infrastructure dashboard as representative of the significance of hydropower to our nation's future.[49]

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goals since EPA provided no specific information on the recalculation of the RE building block under this new approach. However, it seems likely that this approach will only reallocate RE goal among states and not reduce the overall stringency of the RE goal on a national basis. For that reason, MRES will not comment further on this suggestion.

[48] "In 2012, the Department of Energy found that there are tens of thousands of dams across the U.S. that could be powered and add an additional 12,000 MW of hydropower capacity to the nation's electricity grid." http://www.hydro.org/why-hydro/available/industrysnapshot/ (last accessed on November 26, 2014).

[49] "The Administration is also taking steps to encourage the development of hydroelectric power at existing dams. To develop and demonstrate improved permitting procedures for such projects, the Administration will designate the Red Rock Hydroelectric Plant on the Des Moines River in Iowa to participate in its Infrastructure Permitting Dashboard for high-priority projects." The President's Climate Action Plan, at 7. http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf (last accessed November 26, 2014). *See* http://www.permits.performance.gov/projects/complete-projects (last accessed on August 24, 2014).

Furthermore, since the RRHP will come on-line two years before the interim compliance period, it should be allowed to "bank" the renewable energy credits it generates during that two year period for compliance. With significant renewable projects like this hydro plant, it is not possible to exactly time the start of operation with the beginning of the compliance period. MRES should not be penalized by the loss of the value of the renewable credits during this two year period. To do so discourages early development of resources (and early offset of emissions), and sends a signal inconsistent with the President's initiative.

#### ii. Existing hydropower

In addition to new hydropower, existing hydropower should count as an allowable renewable resource for purposes of off-setting $CO_2$ emissions. The proposed rule appears to indicate that measures resulting in $CO_2$ emission reductions at affected EGUs would apply toward achievement of the state's $CO_2$ goal. Utilities and their ratepayers that have existing hydropower in their renewable energy portfolio should be given credit for having a renewable, non-emitting resource that displaces fossil-fuel generation. In its Technical Support Document on this topic, EPA writes off hydropower essentially because it is not widespread. TSD: GHG Abatement Measures, at 4-5. However, data from the National Hydropower Association demonstrates the significance of hydropower. "The existing fleet of over 2,200 hydropower plants already provides the country with 100,000 MW of affordable, reliable hydropower capacity. In fact, the majority of the nation's renewable electricity is generated by hydropower."[50] For at least ten states, hydropower makes up nearly half or more of the generation capacity in their state. *Id*. These states have a legacy of clean, renewable and non-emitting energy, which has displaced $CO_2$ emitting resources, and put them among some of the lowest $CO_2$ emitting states in the nation. *See* note 11. The continued operation of these resources is key to maintaining the status quo, and without this hydropower, energy would have to be replaced likely by natural gas, which would increase $CO_2$ output of these traditionally clean states.

Furthermore, it would be consistent with the methodology that EPA employs in its calculation of renewable energy under building block 3 to include existing hydropower. TSD: Goal Computation, Data File: Goal Computation – Appendix 1 and 2, at Appendix 1 worksheet. EPA includes the total generation in the state, *including* hydropower, in the denominator of its equation for building block 3 when it determines the renewable energy target. *Id.* The 15% goal for renewable energy in South Dakota was based on its total generation in 2012 of 12,034,206 MWh, which includes 5,980,965 MWh of hydropower – nearly half of the total state generation. Because existing hydropower is used in making the calculation of renewable energy targets, it should also be included as an eligible form of renewable energy under building block 3. *See* State of South Dakota Comments. MRES does not advocate for a change in the way that the overall goal target calculation treats generation, excluding hydro from the base.

In its NODA, in addressing whether RE goals should be regional in nature, EPA solicits comments on "whether a regionalized approach should or should not reallocate existing hydropower generation across states (even if all other types of RE generation are reallocated across states under a regionalized approach)." 79 Fed. Reg. 64,551-552 (footnote omitted). This

[50] http://www.hydro.org/why-hydro/available/industrysnapshot/ (last accessed on November 26, 2014).

is a tacit recognition by EPA that existing hydropower is a significant resource. However, it is unclear what effect this change would have on specific state goals since EPA provides no specific information on the recalculation of the RE building block under this approach. It seems likely that this approach has the potential to create dramatic shifts, and some states with vast hydro resources are adjacent to many states with few hydro resources. It has the potential to cause such significant shifts in state goals that it would require a wholesale revision of the manner in which the state goal targets are calculated.

States should be allowed to include policies in their state plans that take into account existing hydropower generation, just as existing wind and solar energy resources are available as options for state goal compliance. The plan should allow a state to designate out-of-nation hydro (such as Manitoba hydro) as an eligible renewable resource; domestic hydro should count as well, all without limitation on size. Further, MRES members do not have an endless supply of hydro; they must contract for this resource just like any other. In fact, they are each in the process of negotiating contracts for the time period of 2021-2050 for federal hydro. These new contracts should be included as eligible renewable resources under block 3.

#### iii. Pumped Storage

Other resources should also be given credit under the Clean Power Plan. For example, EPA suggests that states may recognize in their plans the ability for energy storage to reduce the need for fossil fuel-fired EGUs to provide generation during wind and solar intermittency. 79 Fed. Reg. at 34,924. MRES is in the process of studying the feasibility of the Gregory County Pumped Storage Project to be located along the Missouri River in south central South Dakota. The Federal Energy Regulatory Commission has issued a preliminary permit to study the project, which would provide the necessary control to support a significant amount of intermittent wind generation in the region. Indeed, new pumped storage allows for more RE to be integrated with the electric grid. As written, the Clean Power Plan does not make clear that pumped storage projects are included in the list of energy storage technologies eligible for inclusion in state plans. In addition, the Clean Power Plan does not specify how a state may incorporate energy storage technology. States must be allowed to meet their respective state goals by relying on any technology that has the potential to enhance emission performance by reducing the need for generation from fossil fuel-fired EGUs, and it should clarify that pumped storage is an eligible energy technology under building block 3.

#### iv. Interstate issues

As mentioned earlier, MRES faces a significant interstate issue given the fact that our renewable wind energy resources are located outside the state of Wyoming where our only affected EGU is located. According to the proposed rule, any existing non-hydro renewable energy that is still generating electricity in 2020 can be relied upon in state plans, regardless of the date of installation of that facility. TSD: State Plan Considerations, at 60. As mentioned earlier, MRES has 85.7 MW of wind capacity from the following five wind energy resources:

- Hancock (IA) Wind Project, 3.3 MW
- Worthington (MN) Wind Project, 3.7 MW
- Marshall (MN) Wind Project, 18.7 MW

- Odin (MN) Wind Project, 20.0 MW
- Rugby (ND) Wind Project, 40.0 MW

MRES purchases the energy associated with the wind capacity from the wind projects listed above, and owns all of the environmental attributes associated with such generation (which are each registered with M-RETS). MRES also purchases 32 MW of nuclear power from the Point Beach Nuclear Plant located near Two Rivers, Wisconsin, and has the right to the environmental, non-emitting attributes associated with the energy purchased from this facility. Utilities, and their ratepayers, must have the ability to offset the $CO_2$ emissions from their affected EGUs through the use of non-emitting credits from their clean energy resources located in other states. It is essential for utilities with load and resources in different states that any credit for renewable energy under block 3 of the proposed rule go to the utility and its customers who paid for those renewable energy resources, and associated environmental attributes, to be used for compliance wherever they have $CO_2$ emissions to offset. These resources must be allowed to freely flow across state lines in interstate commerce.

It is important to point out that the ability to use renewable energy in interstate commerce is also supported by regulators. This concern is shared by the State of Iowa, as they pointed out in their comments that "State plans must be allowed the flexibility to count renewable energy that is generated in one state and consumed in another, as long as the generation is not double-counted." State of Iowa Comments, filed November 12, 2014, at page 2.

Minnesota, for example, should not be able to take for its compliance purposes under a state-driven portfolio approach the MRES renewable energy and/or associated credits and claim credit for them when the cost to generate that energy is borne by MRES members located in Iowa, Minnesota, North Dakota, and South Dakota. MRES has no facilities that generate $CO_2$ located in Minnesota, so it should not be compelled to offset other utilities' emissions with renewable energy paid for by its multi-state members. Instead, the MRES members are entitled to expect that the renewable resources they pay for will be fully available to offset the $CO_2$ of LRS, their only affected unit. The principles of cost causation and fiscal responsibility are long-standing in the utility industry, and it is consistent with those principles that MRES members who have been paying for renewable energy since 2001 should get credit for that renewable energy against the $CO_2$ emissions of LRS.

Additionally, the proposal's use of (in some cases only a portion of) existing renewable resources in a state to calculate the baseline but then allow other states where the renewable generation is used to count the generation toward reductions in $CO_2$ is patently unfair to ratepayers and is unconstitutional. *See* Section 3 of these comments, *supra*. As to the ratepayers, the EPA's approach that allows a state with a renewable energy mandate to claim renewable, non-emitting resources in another state toward the reduction and achievement of its $CO_2$ goal is unfair to the customers who have paid for those resources, and presumes to give the state an ownership interest in these private resources. EPA has presumably been under the impression that only customers living in a state with a renewable mandate pay for the construction and operation of those resources. For a regional utility like MRES, nothing could be further from the case. All MRES members pay the same rates for their power supply, which includes an amount necessary to recover the costs of renewable wind energy. *See* note 43. As mentioned above, our various non-emitting resources are located in Iowa, Minnesota, North Dakota and Wisconsin. Minnesota is the only one of our member states that has mandated the use of renewable energy; North Dakota and South Dakota have imposed objectives. The MRES portfolio has sufficient renewable wind energy to satisfy the Minnesota mandate and the North Dakota and South Dakota objectives.

Renewables have to be constructed where the resources exist (and where there is adequate transmission), and those resources are not necessarily located in the same state where all $CO_2$ emitting affected units are located. This fact also demands that utilities that acquire renewable resources should be entitled to use the credits where the utility's system needs them for compliance purposes. Portability ensures that utilities pursue those resources that fit best with their system at the lowest cost, and promote a more efficient and economical generation portfolio and electric grid.

Lastly, it is unclear how the renewable energy needed to be developed as a result of the Clean Power Plan will be constructed within the time constraints set forth in the proposed rule given the significant barriers to mass construction of new renewable resources. As mentioned earlier, it takes several years to construct the required upgrades and build-out of transmission necessary to support additional renewable energy development, not to mention the time required to complete the associated engineering, land acquisition, permitting and construction of the renewable facilities themselves. The reliance of the Clean Power Plan on block 3 will create significant manufacturing demand, which could cause more delays. The time needed to construct additional natural gas units must also be taken into account because of the intermittent nature of traditional renewables like wind and solar. Wind and solar facilities can only produce electricity when the wind is blowing or sun is shining, meaning that other generation sources, most likely natural gas units, will be needed to back up those renewables and maintain a reliable flow of energy.

#### v. Alternative Renewable Energy approach is worse

The proposed rule sets forth an "Alternative Renewable Energy" approach to calculating the renewable energy component to support the BSER. 79 Fed. Reg. 34,869. This alternative approach relies on a state-by-state assessment of RE technical and market potential. At first glance, it appears to solve several issues with EPA's proposed approach that uses Renewable Portfolio Standard (RPS)-based regional renewable energy targets. However, applying this alternative RE approach to EPA's calculation of state-wide emission goals has a profound impact on the current proposed goals. This is particularly true for a state which has already reached its regional RE generation target under EPA's proposed approach.

For example, South Dakota is in the North Central region that has an average regional RE generation target of 15% under EPA's proposed approach. South Dakota has already reached its regional RE target, with 2,915 GWh of RE generation in 2012, and thus its obligation under the target is capped at its share of the 15% regional RE target, 1,819 GWh of RE generation. Under the alternative RE approach, South Dakota's obligation under the target is not capped. Instead, South Dakota's state-level 2030 generation target, excluding existing hydropower, is 19,156 GWh of RE generation. This generation target would be incorporated into the denominator of the state goal calculation in place of the RE generation levels quantified using EPA's proposed approach. Including South Dakota's generation target based on the alternative approach causes South Dakota's final rate-based $CO_2$ emission performance goal to decrease from 741 pounds $CO_2$/MWh under EPA's proposed approach to 185 pounds $CO_2$/MWh under the alternative approach. In other words, the percent reduction in South Dakota's state emission rate – a state with one of the lowest $CO_2$ emissions rate in the nation – that the proposed rule requires would increase from 35% to 84% if the EPA were to adopt the alternative approach for quantifying RE for BSER. EPA's state goal calculation for South Dakota under both EPA's proposed approach and the alternative approach are set forth below.

Final State Goal Calculation[51]

<u>(coal gen. x coal emission rate) + (OG gen. x OG emission rate) + (NGCC gen. x NGCC emission rate) + "Other" emissions</u> = *State Emission Rate*
Coal gen. + OG gen. + NGCC gen. + "Other" gen. + Nuclear gen. uc + ar + **RE gen.** + EE gen.

Final Proposed State Goal Rate for South Dakota – Proposed RE Approach

<u>((958,046 x 2,130) + (0 x 0)) + (1,992,211 x 1,131) + 0)</u> = **741 lb/MWh**
(958,046 + 0 + 1,992,211 + 0 + 0 + **1,818,850** + 1,028,768)

Final Proposed State Goal Rate for South Dakota – Alternative RE Approach, Excluding Existing Hydropower

<u>((958,046 x 2,130) + (0 x 0)) + (1,992,211 x 1,131) + 0)</u> = **185 lb/MWh**
(958,046 + 0 + 1,992,211 + 0 + 0 + **19,156,000** + 1,028,768)

According to the Alternative RE Approach TSD, page 8, states would not be required to achieve the absolute levels of target generation quantified under the alternative approach and incorporated into the denominator of the state goals. Rather, states may consider including in their state plans compliance measures that do not rely heavily on expanding their RE capacity. In practice, however, it is difficult to see how certain states will meet the state targets if EPA chooses the alternative RE approach to be used as part of BSER. The multitude of issues that surround the expansion of RE cannot be adequately taken into account by the use of the Integrated Planning Model as relied upon by EPA to project potential RE generation expansion. As acknowledged in the Alternative RE Approach TSD, page 2, there are limitations to technical potential due to grid costs, development costs, resource quality, and uncertainties of production potential. The expansion of RE is highly dependent on available transmission. Any approach to quantify RE potential should take into account transmission constraints and the issues surrounding new transmission construction that come from siting, permitting, environmental impacts, and landowner opposition. For some states, the amount of renewable growth that EPA expects may well turn out to be unachievable. States should not be forced to make up the difference elsewhere in their state plans for compliance.

### vi. Transmission and natural gas availability

[51] These calculations are based on data from the Alternative RE Approach TSD, page 12, and the Goal Computation TSD containing a Microsoft® Excel attachment of the aggregate state-level data, calculations, and proposed state emission rate goals.

As indicated in Section 6(c) above, natural gas use currently is largely tied to providing peaking power and providing voltage support and inertia to the system to compensate for the variability of wind and solar resources. The expansion of RE will be highly dependent not only on transmission, but also on the continued robustness of the grid. *See generally NERC Report.* The robustness of the grid as it relates to integrating renewable energy is currently provided by natural gas generation facilities (and, in the future possibly, pumped storage). The expansion of RE will therefore require the expansion of natural gas power to follow the load and to compensate for the variability of renewables at a higher level. This increase in natural gas will require build-out of natural gas infrastructure and the build-out of transmission. As indicated above, the construction of natural gas pipelines and transmission require lengthy permitting processes, environmental impact assessments, and additional costs to consumers. The proposed rule and related TSDs do not assess the related impacts to natural gas and transmission and therefore should be revised and re-analyzed to reflect the actual constraints and delays this will cause in RE development and the resulting costs to ratepayers.

## d. Block 4: 1.5% is unrealistically high

Block 4 of the proposed rule assumes that a state plan would reduce carbon dioxide emissions by the use of demand side energy efficiency. Block 4 is based on the assumption that each state would achieve 1.5 % energy savings per year beginning in 2020 and continuing through 2029 and beyond, an assumption that is not supportable. This assumption is based on the top twelve achieving states taken en masse and not on actual studies based on load, demand, or cost-effectiveness, and it does not take into account maximum efficiency achievements. In fact, the proposed rule even cites to the state of Minnesota, commenting that the state has achieved a 13.1 % reduction in demand. However, it is the experience of MRES that such reductions are not being achieved with any consistency now, and are unlikely to be achieved in the future.

### i. 1.5% savings unachievable

EPA's methodology for setting a 1.5% target does not hold up to scrutiny. EPA's proposed 1.5% savings per year is based on an American Council for an Energy-Efficient Economy potential study that was a top-down, policy based study. It arbitrarily rejected the study done by the Electric Power Research Institute (EPRI) that shows savings potential of 0.5 to 0.7% per year achievable potential from a bottom-up, engineering based study.[52] EPA must support its 1.5% goal with actual credible proof of potential. Anything short of that is arbitrary and capricious. Targets should not be based on a policy goal, but on demonstrated best performance. The Maximum Achievable Control Technology concept could be used for EE potential. EPA could take the top 12% of actual savings[53] performance to represent "best in fleet" or "best performance."

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[52] EPRI Report 1025477, "U.S. Energy Efficiency Potential Through 2035," (2014).

[53] Demand-side Management (DSM) Potential Studies typically show 3 levels of potential: Technical potential (assuming ***every*** customer adopts the most efficient available measures, regardless of cost), economic potential (assuming ***every*** customer adopts the most efficient available measures that pass a basic economic screen), and market (or achievable) potential. EPA is suggesting that goals should be based on technical potential. MRES uses market/achievable potential in our IRP process because it reflects the actual facts in our member communities and the measures that are actually adopted by customers, and is consistent with engineering methodology. This takes

Even though EPA uses Minnesota as an example of the appropriateness of 1.5% as the savings goal, it ignores important exceptions in the Minnesota standard and the fact that Minnesota has not actually achieved that savings goal. *See* 79 Fed. Reg. at 34,849; *Minnesota Conservation Improvement Program Energy and Carbon Dioxide Savings Report For 2010-2011*, Minnesota Department of Commerce, Division of Energy Resources, October 1, 2013.[54] In 2007, the state of Minnesota adopted an energy efficiency goal of 1.5% savings per year. The state statute, Minn. Stat. § 216B.241, provides that each municipal power agency, cooperative or utility is to plan and implement programs aimed at meeting at least 1.5% savings per year.[55] Significantly, however, the utilities or associations are specifically "not required to make energy conservation investments to attain the energy-savings goals...that are not cost-effective even if the investment is necessary to attain the energy-savings goals." Minn. Stat. § 216B.214, Subd. 1c(f). Likewise, in 2009, the state of Iowa adopted Iowa Code § 476.6(16)(c) which required utilities whose rates are regulated locally and not by the state utility board, like MRES and its municipal utility members, to undertake their own specific study to assess the maximum potential energy and capacity savings available through cost-effective energy efficiency measures and programs. Under this law, the utility must use this analysis to establish its own cost-effective programs to meet the energy efficiency goal indicated by their studies.

MRES responded by studying the highest potential of cost-effective energy savings achievable in each of the four states it serves members — even in South Dakota and North Dakota, which do not have statutory energy efficiency goals. MRES has observed consistent results in the several potential studies it has undertaken in the last ten years. The results of the studies have consistently found that about 0.7 % savings is the maximum of cost-effective energy savings achievable. The studies are specifically tailored to MRES, *i.e*. the most recent potential study was based on our 61 members and was specific to load (including the top 200 customers), projected demand, customer base, and other relevant factors specific to our members and their customers. *See* "*Assessment of Energy Efficiency and Demand Response Potential*," prepared for MRES by Morgan Marketing Partners, dated October 27, 2014. This 0.7 % that was predicted by the various studies is consistent with the amount of savings that MRES and its members have actually achieved over the past six years as demonstrated by empirical results. MRES municipal utility members, located across the four states of Iowa, Minnesota, North Dakota and South Dakota, are predominately small and rural communities, with the average population of approximately 5,000 people. Communities of this size typically have less potential for energy efficiency savings, with most of their meters serving residential rather than commercial or industrial customers (which typically have more potential opportunities for savings). *See* Comments of the State of South Dakota, Appendix at A-12.

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into account other factors such as customer adoption or rejection of particular technologies, trade ally cooperation or non-cooperation, and other market barriers not related solely to cost.

[54] Available at: https://mn.gov/commerce/energy/images/CIP-CO2-Report-2013.pdf (last accessed Nov. 7, 2014).

[55] Although certain provisions the Next Generation Energy Act which enacted the 1.5% annual conservation improvement program savings standard have been invalidated as unconstitutional, the provisions relating to this energy efficiency standard were not at issue in that litigation. *See North Dakota v. Heydinger,* 15 F. Supp. 3d 891 (D. Minn. 2014).

Further, as stated previously, MRES began its EE programs in earnest in 2008 with the development of its Bright Energy Solutions program.[56] We have engaged with residential, commercial and industrial consumers, as well as trade allies. These efforts have resulted in a savings, from calendar year 2009-2013 of 26,330.454 kWh at an average annual cost of approximately $600/kWh. While these efforts represent significant savings over time, appliance, motor, compressor and other efficiency elements embodied in various codes eventually reach a "maximum efficiency" level due to technology constraints, thermal limits, size limits, and economic and other conditions, such as diminishing returns. The results are also skewed because state programs – as well as EPA's proposal – do not capture the real value of replacement savings rather than the difference between the current standard and the efficient model incentivized.

Due to the reduced availability of cost-effective energy efficiency gains as energy standards are approaching "max tech," and increased EE standards that will become effective in the 2015-2018 time frame, the ability to achieve more efficiency has been significantly limited than was contemplated by EPA in its goal setting process. The dual effect of these limitations when taken together with early action to implement EE well before the baseline year of 2012 or the effective date of 2020, means that the EE assumptions that lie at the heart of block 4 do not represent the actual conditions in the industry for those utilities that have been proactive. EPA needs to reconsider its proposed best practices level of EE performance to reflect actual conditions and feasibility of further efforts.

At the end of the day, however, it is not MRES or its municipal utility members that will achieve the projected 0.7 % savings — but the end-use customers. The utilities can only provide incentives and encouragement to prompt customers to make investments or behavioral changes in electric energy use. To undertake those actual investments or changes lies solely in the free will of the customer; MRES studies on energy efficiency potential necessarily take into account the "buy-in" that customers are willing to make based not only on economics but also on other barriers that are customer-specific, as well as the historical achievements to date. However, block 4 is based on the unproven assumption that customer buy-in and action will be consistent in its impact on energy use and generation needs regardless of cost or other barriers and taking only into account availability of technology. Our studies are based on our actual customers, use, and load, and show otherwise. The EPA reliance on block 4 overestimates the ability of the state or the utilities to change the habits of individuals or to cause the consumer to undertake investment in savings in order to consistently achieve 1.5 % per year savings, and consequently overestimates the savings available from block 4 in setting target goals. EPA failed to undertake any engineering studies on what is actually achievable and instead based the 1.5 % per year savings by cherry-picking the most optimistic policy review.

Additionally, changes in manufacturing codes and building codes means that customers only have certain options available to them. For example, as appliances fail, most residential customers would only find EnergyStar™ certified appliances available to them. It is nearly impossible for utilities to take EE credit for this customer "choice." Also, as customers choose more efficient appliances, windows or other options, the availability of the next increment of savings declines and makes the incentive for that next increment more expensive. As the low-

[56] *See* Bright Energy Solutions website at www.brightenergysolutions.com.

hanging fruit gets picked, the next increment of savings becomes more difficult, less cost-effective, and less likely for customer buy-in if it involves significant investment or consumer behavioral changes.

Finally, EPA block 4 analysis also assumes that all energy efficiency programs are cost-effective; clearly, that is not the case. Iowa and Minnesota state law require energy efficiency programs to be cost effective as part of the state rate protection for consumers. If the EPA assumes that the 1.5 % *must* be achieved regardless of cost effectiveness, then the assumptions have failed to meet the adequately demonstrated requirement of BSER. 42 U.S.C. § 7411(a) (1). At a minimum, EPA must include an economic safety valve in its proposal to protect consumers.

EPA's assumptions are so skewed as to make compliance with the 1.5% per year standard a distant and unattainable goal for most utilities, especially relatively small municipal entities like MRES and its members. As explained, MRES has engaged in concerted efforts at conservation, both for our member utilities and for their customers, since 2008, and operate our Bright Energy Solutions program in all four member states of Iowa, Minnesota, North Dakota and South Dakota. Over the years, experience has consistently demonstrated actual efficiency gains that average 0.7% per year. We have also engaged consultants to assist in identifying additional cost-effective energy efficiency for the future and to project the likely effectiveness of such programs. As noted, the current energy efficiency potential study has projected future energy efficiency rates of 0.7%, matching the results we have been experiencing for six years.

It is important that the energy efficiency efforts that are ongoing, and the results achieved since the publication of the rule in June 2014, should be counted toward compliance with any state plan. Allowing banking of energy efficiency credits is essential to maintain the momentum of existing programs. *See* Comments of the State of South Dakota, Appendix at A-14. Without that, utilities and third parties will have little incentive to continue efforts and, indeed, would be wise to withhold further action until it would count in 2020.

In addition, given that a 1.5% goal is overly ambitious, it will not be adequate to absorb anticipated load growth. There is nothing in the Clean Power Plan that acknowledges the reality of load growth in the residential, commercial or industrial sector in general, or in specific regions of the country. For example, North Dakota is experiencing double-digit load growth in the western portion of the state due to the development of the Bakken oil reserves. Without accounting for load growth, the Clean Power Plan reveals a fundamental limitation of its structure, yet again revealing a substantial disconnect with the reality of the United States economy and the operation and function of the electric industry.

#### ii. Alternative approach preferable

EPA's proposal includes two options for setting the EE goals or mandates, using 2012 data as the baseline: Option 1) 1.5% "goal" starts in 2017 and continues thru 2030 and beyond, or Option 2) achieve 1.5% in 2020 and then a "goal" of 1.0% after that thru 2025. 79 Fed. Reg. 34,873. MRES does not support either option to its fullest. While both options will flatten the utility's load curve, given the reality of the challenge of actually achieving energy efficiency, it is more appropriate that the alternative approach offered by Option 2 be adopted (or that it be lowered further). Because the supposition that 1.5% savings can be achieved each year is inaccurate, it is preferable that the alternative which aligns more closely with actual achievable results is employed by EPA. In the end, EPA should re-evaluate the methodology and assumptions used to calculate block 4 savings in each state, and should adopt a less aggressive and more realistic approach.

#### iii. EM&V standards and credits require additional time

Even assuming building block 4 is workable, it will take substantial time to implement. First, states need time to prepare standard evaluation, measurement, and verification (EM&V) terms, a complex undertaking. As noted earlier, it is important that EM&V standards be consistent and acceptable across states to facilitate the interstate use of credits. Given the considerable technical analysis that goes into EM&V standards development and associated technical manuals, the most expeditious approach available would be for EPA to identify the various state-approved measures, and allow states without such measures to choose among the existing mechanisms that are already in place.

Second, for utilities and others to develop new energy efficiency programs, especially where we have been doing so for many years, will require additional innovation to develop new programs, as well as implement them. Also, it will require substantial time for states or third parties to develop a credit system for energy efficiency. Unlike renewable energy, there is no existing mechanism that is widely known to standardize the process to ensure that a kilowatt (or megawatt) saved is equivalent to a single EE credit, and that those credits are tradable like those for renewable energy to offset emissions on a one-to-one basis. Also, like credits generated under building block 3, those generated under building block 4 for energy efficiency and demand-side management must be portable under state and federal plans. Utilities and their rate-payers have bought and paid for those efficiencies, and the associated credits should be available to them to offset carbon dioxide emissions.

## 7. Plan Approval, Implementation and Enforcement Issues

The preamble's extensive discussion of the way in which EPA anticipates that the Clean Power Plan will work reveals that there will be a number of issues that also arise once a state has drafted its compliance plan. The construct of the rule demonstrates that issues will be created when a plan is submitted for approval, as well as after it has actually been approved by EPA. While a number of those issues have been identified above, the following discussion identifies some particular issues that EPA should address if the Clean Power Plan is to function.

### a. Plan Approval

Given that states are allowed only one-year (with the potential for a 12-month extension under certain conditions) to develop a plan, EPA will be flooded with state plan approval applications. The process for approval that will create a federally-enforceable plan is going to take time for EPA regional offices to process in this first-of-its-kind regulatory scheme. In fact, EPA deviates from its standard four-month review period to allow EPA review to take a full year, a tacit acknowledgement that this unprecedented regulatory structure is excessively complex. 79 Fed. Reg. 34,838. While EPA's preamble outlines general and specific criteria for evaluating plans, states will nonetheless be subject to a great deal of uncertainty in this initial exercise. *See id*. For a state plan to be approved by EPA, the Clean Power Plan requires, in addition to other criteria, that the plan contain enforceable policies that reduce $CO_2$ emissions from affected EGUs. To be enforceable, these policies must quantify and verify any reductions that take place under the state plan. While changes in generation at an EGU are readily verifiable through permitting and mandatory reporting requirements, the remaining building blocks require a new paradigm be developed by each of the states to create enforceable and verifiable reductions.

EPA must provide clear and unequivocal guidance to states regarding renewable energy and energy efficiency in order to ensure that plan approval processes are consistent. Without the modifications to the building blocks suggested above (and summarized below in Section VIII), EPA will invite disparate treatment of renewable energy and energy efficiency among states. It will create a circumstance where states rush to submit plans in order to be the first to get their approach to RE and EE approved and thus, set a "standard" for what can be approved. This will force EPA to follow the approach adopted in the first approved plan or risk creating conflicts with subsequent approved plans. This can occur not only within the same EPA Region (for example, between North Dakota and South Dakota), it is likely to occur between Regions (such as Iowa and Minnesota).

For example, if Minnesota and North Dakota disagree over whether Minnesota can count North Dakota wind under building block 3, Minnesota could expedite its rulemaking process in a race to beat North Dakota's plan submission and approval. Assuming Minnesota did so, and included a provision that allows it to count out-of-state wind in North Dakota (and elsewhere), the approval of Minnesota's plan would effectively prohibit North Dakota from counting wind located in its own state and owned by utilities that operate fossil facilities in North Dakota. Because Minnesota is located in EPA Region 5 and North Dakota is in EPA Region 8, it not only sets up a conflict between the states themselves, but potentially creates a Region by Region conflict. Thus, if Minnesota also claims a right to count for compliance under block 3 all wind physically located in the state, and that portion of its plan is likewise approved, it sets up another conflict with Iowa (in Region 7), for example, where utilities in that state have wind purchase power agreements from facilities located in Minnesota.

Similarly, unless EPA states in uncertain terms that all renewable energy and energy efficiency is the property of the utility owner and freely transferable for use in any state, it creates a regulatory morass where Wyoming, for example, could allow a utility to use RE and EE generated elsewhere to offset $CO_2$ emissions in the state, while Minnesota claims that it is entitled to use for its own compliance all RE and EE within its state borders. The only way that the plan approval process can proceed in a methodical and consistent way is for the Clean Power Plan to resolve all of these issues in the final rule. If it fails to do so, there will be a patchwork of competing plans and little certainty as to whether the rule has achieved its objectives in fact.

Another issue previously noted is that EPA should provide additional guidance on approvable EM&V tools and methodologies for state plans that include policies that allow compliance to be achieved through the use of renewable energy or demand-side energy efficiency actions. To the extent a state plan relies on energy efficiency, it remains unclear how energy efficiency mandates would be made enforceable under a portfolio approach when it is the customer's decision to undertake an energy efficiency measure. Emission reductions obtained through energy efficiency depend largely on customer investment and behavioral change. While the preamble suggests that states can impose compliance obligations on entities other than EGUs, including end-use consumers, it begs the question of whether customers can be required under a state plan to undertake energy efficiency measures. 79 Fed. Reg. 34,871. Furthermore, municipally-owned utilities and electric cooperatives are not currently subject to state jurisdiction for energy efficiency. This could require new state legislation in many states to extend this jurisdiction (which MRES does not support), which will amount to a major change and increased compliance costs for these non-jurisdictional entities. EPA must resolve this issue by stating that the building blocks can only be used as ***optional*** compliance tools, and that the use of the blocks cannot be mandated in state plans. Without that definitive clarity, states will be without a way to demonstrate the enforceability of EE measures, for example.

All of these hurdles could be overcome if EPA were to mandate that states use the utility-driven portfolio approach, and adopt a plan that gives the utilities the flexibility to choose from among the four building blocks and other approved measures to achieve the necessary reductions from each EGU, rather than attempt to mandate action under any individual block. By providing utilities the flexibility to choose from among the approved measures, it ensures that responsible integrated resource planning can continue to focus on the traditional goals of balancing the costs of electricity with the obligation to provide reliable service, while still achieving the GHG goals of the Clean Power Plan. It also avoids the necessary state jurisdictional issues that are presented when states look for authority to impose building block mandates on municipal utilities and cooperatives.

If states are allowed to impose the building blocks as mandates, the ability of a state to submit an approvable state plan that demonstrates compliance with the interim and final goals is impractical because, as noted above, the BSER assumptions are inaccurate and the building blocks are unworkable. Given this fact, a viable state plan should be one which includes as options – not mandates – the use of the building blocks and other emission reducing activities (*e.g*. emission reductions in the agriculture and transportation industries), and allows EGUs and utilities to choose the most practical and cost effective manner of achieving the state-imposed $CO_2$ reduction goal. States can craft their compliance plans to develop enforceable milestones (assuming that states are given control of the glide path and interim goals of 2020-2029), and penalties for failure to meet those milestones.

### b. Implementation should not be left to RTOs

Regional Transmission Organizations or Independent Transmission Operators are ill-suited to implement the Clean Power Plan. RTOs are federally-approved entities that are not subject to state jurisdiction. FPA Section 215, 16 U.S.C.§ 824o; *see* FERC Order 2000, 89 FERC 61,285. A state plan could not force an RTO to alter its operations to meet the state's plan (which might well conflict with another state's plan), nor could a group of states do so in the case of a multi-state plan. Likewise, EPA cannot force RTOs to alter operations to accommodate the scheme devised by the Clean Power Plan; FERC is the federal agency that has jurisdiction over them. *Id.*

This EPA proposal is designed to limit emissions from power plants. The expertise of RTOs is in running electricity markets and maintaining the reliability of the interconnected grid within their respective regions, not monitoring or controlling the emission of pollution from electricity that flows across the transmission network. RTOs must remain focused on their essential duty to operate the grid to ensure reliability, as well as ensure an efficient functioning market.

The emphasis in the proposal on redispatching NGCC resources and shifting to non-emitting resources forces choices among generating resources. However, those choices should remain the responsibility of utilities which are responsible for compliance with $CO_2$ emission reduction goals, and will be answerable to the state plans that govern their operations. In terms of accounting for the shifts in the makeup of utility generation, mechanisms exist now that can be adequate to demonstrate compliance.

For example, there are a number of entities that are in the business of certifying the generation of renewable energy and creating unique identification systems that establish credits for such generation. The Midwest Renewable Energy Tracking System (M-RETS®), for example, is used by Illinois, Indiana, Iowa, Manitoba, Minnesota, Montana, North Dakota, Ohio, South Dakota, and Wisconsin to verify compliance with state and provincial renewable energy requirements.[57] "M-RETS® uses verifiable production data for all participating generators and creates a Renewable Energy Credit (REC) in the form of a tradable digital certificate for each MWh," a process which helps to ensure that there is no double-counting of RE to meet regulatory requirements in multiple states. It is also important to recognize that the use of a REC to meet a state requirement is not inconsistent with the use of that same energy to demonstrate compliance with block 3 compliance mechanisms. *See* State of Iowa Comments. In a similar manner, systems will also develop for the systematic crediting of energy efficiency savings, independent of RTOs.

### c. Inability for state to react to unintended consequences/market issues

Traditionally under the Clean Air Act, each state is allowed to prepare a state plan based on the state's own determination of how to best meet and achieve the EPA emission standards. *See generally, e.g.*, 42 U.S.C. § 7412 (hazardous air pollutants). Usually, the EPA will publish a guideline document containing information regarding the control of a designated pollutant from designated facilities. The guideline is to include a description or application of the best emission reduction and has been adequately demonstrated for the designated facilities. After the guideline is published, each state then prepares and submits a plan containing performance standards for the designated facilities in the specific state, a description of the best system of emission reduction, and the timeline, as well as alternative methods of achieving the required level of control. Here, the EPA has issued an emission guideline that does not apply directly to stationary sources, but rather forces state requirements in such "outside the fence" areas of renewable energy development, energy efficiency and redispatch of resources. In particular, renewable energy and energy efficiency are variable resources at best. Wind and solar are

[57] *See* http://www.mrets.org/ (last accessed November 25, 2014).

intermittent. Energy efficiency, likewise, is subject to ups and downs in the amount achieved by consumer action. Finally, dispatch of natural gas over coal, or the dispatch of renewables over fossil fuels is a decision outside of the jurisdiction of the states or the utilities. Dispatch is based on demand profiles, cost, reliability, and timing within the control of the RTO.

Given that the practical development and production of electricity is subject to so many variables beyond state control, a state plan must have the ability to adjust to actualities and unexpected and unintended consequences that are experienced "on the ground"—some of which cannot be anticipated. Simply suggesting that state plans be "self-correcting" does not provide the necessary mechanism to allow for changes to state plans. *See* 79 Fed. Reg. 34,909-34,910.

States must be able to amend plans, and to provide alternatives, off-ramps, or delays as necessary to assist utilities in meeting the statutory obligations and to comply with the Clean Power Plan while maintaining a robust transmission/distribution grid while keeping high reliability. However, once a state plan is submitted and approved by EPA, it is a federally enforceable plan and may not be altered. For example, a state may adopt a renewable energy mandate as part of its state plan. A few years into implementation, severe transmission constraints might arise or transmission construction might be delayed by litigation, limiting the amount of renewable power that can be carried. A state cannot adjust the interim milestones to allow for the time of transmission build-out ahead of the renewables; their hands are tied because a state cannot change its plan to lower the renewable mandate and to increase natural gas dispatch to meet the unexpected transmission challenge. Likewise, technology may develop to the point that a state legislature may abandon its renewable energy mandate in favor of carbon capture technology (assuming its development eventually occurs at a commercial level). If the state ends the renewable energy mandate in favor of another technology — even one that creates more GHG savings, that state cannot simply change it at the legislature, but rather it is "stuck" until such time as an extraordinary application for modification is made under Clean Air Act § 111(f) and the state plan is re-written, re-submitted to the EPA, re-evaluated, re-opened for comment and hopefully approved by the EPA.

### d. Enforcement Issues

Also, the proposed rule requires that all state plans, including multi-state plans, identify enforcement measures for affected entities. States need more clarity from EPA on what enforcement measures would meet EPA approval under a state or multi-state plan and how such plans are expected to be enforced at the time of compliance. Although the proposal asserts that it provides states with flexibility, it does not provide any flexibility for addressing unanticipated changes and events that might occur after plan approval that will significantly impact the ability of the state to achieve its objectives under the plan. Such an occurrence should not automatically result in federal enforcement or subject an entity with a compliance obligation to citizen lawsuits. The plan must be modified to allow states to make adjustments to their enforcement plans when they demonstrate a justifiable reason to alter the level of performance required under the approved plan.

Other uncertainties regarding enforcement permeate the proposal. For instance, if a state fails to meet its targeted reduction through redispatch of NGCC during the ramp-up that must occur in

2020 because of a lack of transmission capacity, does EPA (or do the other states, in the case of a multi-state plan) bring an enforcement action against the state? If EPA brings a federal enforcement action, would it be brought against all the participating states in the multi-state plan, or only those states in the plan found not to be contributing to compliance? Also, what if customers in a state fail to subscribe to sufficient energy efficiency? Does EPA or all the states in the plan hold the underperforming state liable? What are the penalties for non-compliance? These questions are significant and need clear answers from EPA in order to assist states in their decisions on whether to join one or more states in developing a multi-state plan.

The Clean Power Plan raises a number of important issues and questions regarding how the rules are to be enforced, including:

- How would EPA prosecute a federal enforcement action against a state that took obligations upon itself in a state-based portfolio approach?
- Do states face potential monetary penalties for not complying with the proposed rule? If so, do ratepayers within the state pay the fine?
- Could an EPA enforcement action require a state legislature to modify a renewable portfolio standard?
- How would a multi-state plan be enforced? Would all the participating states in the multi-state plan be subject to a federal enforcement action, or only those states in the plan found not to be contributing to compliance?

The proposed rule appears to rely, to some extent, on citizen suits for enforcement. Abdicating enforcement to third parties causes the loss of flexibility and regulatory certainty for long-term power planning and reliability horizons. There is also uncertainty as to whether the state-driven portfolio approach under the proposed rule allows citizen suits against states (or non-EGUs). This potential for citizen suits could result in significant additional costs.

## 8. MRES Proposed Solutions

While Section 3 details the reasons that the EPA's Clean Power Plan is illegal and unconstitutional, we recognize that this position may not prevail, and we must be prepared to control GHGs. Missouri River Energy Services believes strongly that in commenting on the proposed rule, it should not only point out the problems that are unworkable and potentially fatal flaws, but it must also stand ready to find a way that the ultimate goals of the proposal can be achieved in a workable and cost-effective manner for MRES and its municipal utility members. We believe that many of the problems posed by specific elements of the proposed rule can be avoided with relatively minor changes to the rule and a consistent approach to approvable state plans. Furthermore, we believe that this approach will work for the entire industry – investor-owned utilities, cooperatives, and municipal entities alike – and minimize the regulatory burden on the states. Here we summarize the solutions to the issues we have identified above.

## a. Pathway: Utility-driven portfolio approach only viable option

To begin, the EPA should withdraw the first three pathway options, and require that all states approach the development of their state rule from the utility-driven portfolio approach. Regulating utilities and their emission rates is the function of state air and environmental agencies, and this approach is consistent with the manner in which the industry has been regulated historically. It also eliminates the workability barriers of the other approaches and potential unconstitutional operation of the other pathways. This allows states to focus their efforts on crafting a rule that applies to utilities that emit $CO_2$ in their states to meet appropriate state reduction targets, and to utilize the rule's flexibility where it is most meaningful. It also minimizes significantly the likelihood that states will submit inconsistent and conflicting plans, and furthers efficient EPA review of proposed state plans.

## b. Acknowledge states' authority to set each utility's $CO_2$ goal based on the average emission rate of the utility's affected units in the state and the state goal, giving utilities the option of either a rate-based or mass-based approach

Under this approach, each state will assign to the individual utility that has (or utilities that have) affected unit(s) in their state the $CO_2$ emissions reduction goal established by EPA. That goal will be stated as both a rate-based goal and a mass-based goal, and the utility will have the option to choose which approach it will use for its system compliance in that state. This goal will be imposed as a limit that must be achieved by the utility within the state, and may be accomplished by averaging the goal across each of the affected EGUs a utility has located in the state (its utility portfolio within the state). It also avoids an outcome requiring non-emitting utilities in the state to undertake expensive RE or other investments to benefit emitting utilities at the expense of non-emitting utility rate-payers.

## c. Clarify that each utility is responsible for its $CO_2$ emissions generated in the state by its affected units

One of the outstanding features of the utility-driven portfolio approach envisioned here is that it is fundamentally fair. It honors the long-standing maxim that cost causers should bear responsibility for those costs directly. In this case, emitters of $CO_2$ are directly responsible for reducing the $CO_2$ emissions from their affected units, and non-emitters are not unjustly burdened with the expense of cleaning up after their competitors. This also avoids the legal issue over whether the EPA has authority (and by extension, the states) to go beyond the fence line to impose regulations on parties other than those responsible for emitting $CO_2$. It also provides a simple, easy to explain basis for imposing these specific regulations. Emissions from power plants are the target of this regulation; it only makes sense that the power plant sources are the entities regulated by this rule.

### d. Give states authority over the glide path to set interim goals for 2020-2029

One necessary modification to the proposed rule is that it should delegate to states the complete authority to establish interim goals during the 2020-2029 glide path up to the EPA's final goal imposed in 2030. This necessary change (addressed in the NODA) will address a major shortcoming of the rule as proposed, *i.e.* it will allow for the consideration of remaining useful lives as mandated by CAA § 111(d)(1)(B). In addition, it also allows the states to address many of the timing issues created by the rigid 2020 interim goal that requires 80% of reductions be achieved in such a short time frame. This will give the states the opportunity to consider the necessary time frame needed to plan, permit and build needed infrastructure required by blocks 2 and 3 as they establish milestones for utilities to meet during the glide path. It also provides time to develop EE credit tracking mechanisms. Most importantly, it allows states to work with the industry and other stakeholders to develop their plan to meet the 2030 final goal in a manner that reflects the nature of their existing fleet, their renewable potential, and allows for the most cost-effective approach to prevent economic chaos during the interim period.

### e. Give states 5 years to develop state plans, and 8 years to develop multi-state plans

In addition, once the rule is finalized, more time is essential for states to develop their compliance plans. Even if states are limited to just one pathway to consider, there remains a myriad of issues for them to work through in a thoughtful and methodical manner if they are to create a plan (whether self-correcting or not) that they will not be able to modify once it has been approved. When regulating other pollutants under the Clean Air Act, states are given much more than 12 months to develop their plans, and it is only reasonable that they be allowed five years to prepare their compliance plans for this unprecedented regulation. This will also enable regulators to get through the legislative and administrative rule-making processes, where required. Furthermore, if states are to be encouraged to collaborate on a multi-state approach, even more time is necessary to bring together a diverse group of states with widely varying $CO_2$ reduction goals, resource fleets, and renewable energy and energy efficiency potential. The experiences of the RGGI states and the MGA demonstrate that an eight-year time period is reasonable in which to craft a collaborative approach that can gain the support of multiple states. These extensions of time for plan development (and corresponding extensions of compliance deadlines) are critical if meaningful and effective state plans are to be crafted and adopted by the states.

### f. Establish building blocks as optional mechanisms for compliance, together with any other approved measures

As states work to develop their utility-driven portfolio plans, EPA should direct them to make available the building blocks, and any additional state measures, as optional tools available to the utility to select from in finding the most effective way to achieve its final $CO_2$ reduction goal. States should be made to understand that the building blocks are not required to be imposed as mandates on any entity, and a mandate is not required, for example, in order for renewable energy to be available under block 3. Instead, because only utilities with affected EGUs in the state are regulated, mandates are unnecessary to achieve compliance. The obligation of the utility to achieve its mandatory $CO_2$ reduction creates the only incentive necessary to ensure the further development of non-emitting resources and energy efficiency. As long as the state plan allows utilities to use these building blocks for compliance, and the credits are freely transferable in interstate commerce, their inherent value to the utility is assured, and no mandate is required. This eliminates much of the uncertainty surrounding the ability to obtain legislative approval and to do so in a limited time frame.

### g. Recognize that both renewable energy and energy efficiency credits are the property of the utility (and its ratepayers) and are freely portable in interstate commerce to use for compliance in offsetting $CO_2$ emissions in another state

Under any version of the Clean Power Plan, it is absolutely essential that RE and EE credits/attributes be treated fairly. The utility or third party that owns the credits must be allowed to exercise its property rights to use those credits in any state of its choice. The rule should not create a presumption that, for example, wind built in North Dakota to meet the Minnesota RES is attributable to Minnesota. That fiction cannot withstand constitutional scrutiny, and would alter the free market structure which allows for the most economical development of renewable resources. Explicitly recognizing the owner's property rights in RE and credits – and requiring states to do the same – is essential to the effectiveness of integrated resource planning in which utilities carefully plan how to meet their obligation to provide reliable electric service in an economical and environmentally sensitive manner, while complying with applicable laws, and their governing bodies approve the best approach for the ratepayers and consumer-owners. Further, it avoids the absurd disincentive to build renewable resources, for example wind in wind-rich states like North Dakota and South Dakota, that would exist if utilities were not free to use their credits in whichever state they choose to meet any regulatory requirement, such as the $CO_2$ reduction obligation.

### h. Block 3:

#### i. Include new hydroelectricity as a renewable resource, including banking of credits for generation since the publication of the rule

It is important that EPA make clear that block 3 requires that new hydroelectricity resources qualify as renewable energy under any state plan. Presently, the rule acknowledges that incremental or later-built facilities can be included by states as eligible resources under block 3. 79 Fed. Reg. 34,867. Hydro power is inherently clean and produces no emissions when it generates electricity using the inertia of falling water. EPA should make it unequivocally clear that states are required to include as eligible resources new hydroelectricity that has been constructed after the publication of the proposal or become commercially available after the publication date without regard to the size of the facility, date of installation, or increase in capacity. Furthermore, because the construction and commercial operation of these new resources cannot be precisely timed to coincide with the beginning of the compliance obligations, new hydro should be allowed to bank credits for generation produced from its commercial operation up to the date the compliance obligation goes into effect.

#### ii. Include new contracts for existing hydroelectricity as a renewable resource in the year in which it is generated

EPA should also add to the specifics of block 3 a statement that makes it unequivocally clear that states can include new contracts for existing hydroelectricity as eligible renewable resources available for compliance. As noted above, hydro power is non-emitting and provides consistent, base load power. Including existing hydro is also consistent with the formula by which renewable energy goals are established by EPA, which includes all energy generated in a state, including hydropower. While existing hydro admittedly does not add new resources to the nation's fleet, its wide use eliminates the need to rely on fossil fuels for base load needs. If existing hydroelectric dams are not relicensed or are otherwise required to be decommissioned, it will create new demand for base load resources which most likely will be provided by natural gas and will increase $CO_2$ emissions. By allowing hydro to count as an eligible renewable resource, it will encourage the continued operation of these vital national resources. Furthermore, such facilities not only provide renewable energy, but hydro provides much-needed system reliability, voltage regulation, frequency response, spinning reserves, and other essential ancillary services (services that wind and solar cannot provide) that make it among the most important of renewables to meet the nation's greenhouse gas policies.

#### iii. Include pumped storage as a renewable resource

EPA should also make clear that block 3 requires that pumped storage resources qualify as renewable energy under any state plan. As drafted, EPA's proposal does not address pumped storage at all. However, like conventional hydroelectricity, its operation provides base load non-emitting generation to the grid. In particular, pumped storage stores energy in the form of water in an upper reservoir, pumped from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines in the same manner as a conventional hydropower station. Excess energy from the grid recharges the reservoir by pumping the water back to the upper reservoir, usually during nights and weekends when electricity demand is low. Pumped hydro offers an important opportunity for more wind and other intermittent RE resources to provide the energy for pumping, creating an expansive market for development and use of such RE resources. Pumped hydropower storage accounts for 98% of all energy storage in the United States. MRES is currently in the process of assessing the feasibility of a pumped storage facility in Gregory County, South Dakota. Pumped storage provides non-emitting energy as well as valuable ancillary services, in conjunction with RE to provide energy pumping, and is able to do so to meet peak demand. It should be included as an eligible resource under all state plans (which are free to establish eligibility criteria).

#### iv. Non-emitting generation and associated credits must be portable, capable of use in states other than where generated and recognized the same as if generated in-state

One of the most fundamental issues that EPA must clarify in its final rule – in unequivocal language – is that all non-emitting energy, including nuclear power, and associated credits/attributes can be used in any state for compliance, regardless of where it was generated, and it must be recognized at face value. EPA must leave no doubt that the owner of the generation has the sole right to determine when and where to use the eligible generation and/or its credits/attributes for compliance purposes. It must clearly provide that no state may unilaterally claim a right to utilize generation and/or credits/attributes to which it does not directly have title, and only the owner can decide where to use them to meet regulatory requirements. It is essential that states recognize out-of-state generation on a megawatt-for-megawatt equivalent basis.

Utilities have developed their portfolio of resources to achieve certain goals, among them reducing carbon emissions through the use of renewable resources. In doing so, they have been free to choose such resources based on where the resource is located, the nature of the resource (intermittency, for example), the capital costs, the operating costs, available transmission, permitting and land use acquisition, and other factors that go into the overall economic and reliability assessment of each resource. Like countless other utilities, MRES has acquired wind resources in areas with optimal wind profiles (Iowa, Minnesota and North Dakota) in order to diversify its resource mix with non-emitting resources in a cost-effective manner for its members and their customer-owners. MRES and its members have bought and paid for these resources, and have title to the energy and attributes associated with them, just the same as the rest of its resources, including Laramie River Station. EPA must make it clear that this proposal does not in any way authorize the interference with contract or property rights of utilities to their own generation, and those utilities are free to use the non-emitting resources and attributes in interstate commerce without fear of any state-imposed restrictions.

## i. Block 4:

### i. Use an alternative option to set goal to achieve a more realistic energy efficiency goal.

EPA should adopt an alternative option for energy efficiency which uses a more realistic goal that reflects the actual level of performance that is achievable, such as the 0.7% that is demonstrated by empirical evidence of the MRES membership. The alternative Option 2 suggested by EPA provides for a 1.0 % annual incremental savings to calculate state goals which is admittedly closer to the actual level of performance that is achievable (0.7%), and reflects a goal setting process more closely aligned with actual conditions, but it is still too high. (Option 2 also uses the 0.15 % per year level for the pace at which incremental savings are increased from their historic levels.) Using an alternative which sets the initial EE savings at 0.7% in 2020, and then requiring it be maintained at 0.7% through 2025 and beyond (along with the incremental 0.15% annual increase), this approach is preferable to the flat 1.5% goal which MRES has established is not achievable. EPA should use the alternative approach to calculate a more rational goal for states.

### ii. Include banking of credits for energy efficiency gains since the publication of the rule

While MRES believes strongly that states should not be required to mandate the use of the building blocks and that they should be optional mechanisms, utilities should be encouraged to continue and ramp up (if possible) EE efforts by allowing the banking of savings achieved since the publication of the rule. Given the challenges in achieving demand-side energy efficiency gains, it would be counterproductive to deny the use of EE savings in the interim before 2020. If that policy is pursued, utilities and third parties will be incentivized to defer any and all EE efforts until such time as they can use them to offset $CO_2$ emissions.

#### iii. All energy efficiency savings must be portable, capable of use in states other than where saved and recognized the same as if saved in-state

Like the compliance option of using non-emitting energy under block 3 to offset emissions, EPA must make explicit that energy savings must also be available for compliance in any state, regardless of where the savings occur. As long as energy savings are certified under an approved EM&V methodology, they should be capable of use in states other than where saved and recognized the same as if saved in-state. Utilities and their ratepayers make significant financial investments to achieve EE savings, and they are entitled to the benefit of their expenditures made to reduce energy consumption and demand savings that avoid emissions. Again, EPA must make it clear that this proposal does not in any way authorize the interference with contract or property rights of utilities to their own energy savings, and that utilities are free to use those savings in interstate commerce without fear of any state-imposed restrictions.

## 9. Conclusion

The Laramie River Station coal plant is the only base load facility in the MRES generation fleet, and it is co-owned with five other utilities. MRES does not have unilateral decision-making authority over its operation in the short or long-term when it comes to MRES compliance with the proposed Clean Power Plan. We do not have a fleet of coal and NGCC resources to average emissions across, and LRS is in Wyoming, remote from our load in Iowa, Minnesota, North Dakota and South Dakota. These facts present significant barriers to compliance under the proposed construct of the Clean Power Plan.

EPA's proposal should be withdrawn because it is both illegal and unconstitutional. Not only does it encroach on state jurisdiction, it goes far beyond the authority Congress delegated to EPA through the CAA and is inconsistent with the FPA. Equally compelling is that the proposal creates an unconstitutional structure for regulation, exposing the agency's disregard for the basic tenets of the Tenth Amendment state sovereignty, the Fifth Amendments Takings Clause, and the Article I Contracts Clause.

Assuming the Clean Power Plan survives legal challenges, the only pathway for state plans to achieve compliance that is viable is the Utility-driven portfolio approach, and that approach must allow each utility to manage its renewable credits – regardless of where they are generated or whether they were constructed to meet a state mandate – to offset its own $CO_2$ emissions to achieve compliance. It is essential if the Clean Power Plan has any hope of working that renewable credits must be portable across state lines in interstate commerce. Not every state has the same potential for renewable resources and, even if they did, the rush to construct renewables and the associated engineering, land acquisition, permitting, construction and transmission required would cause delay that would extend far beyond the 2020 interim compliance period and potentially surpass the 2030 compliance deadline.

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/s/

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