ORAL ARGUMENT NOT YET SCHEDULED

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, LIGNITE ENERGY COUNCIL, NATIONAL MINING ASSOCIATION, MINNKOTA POWER COOPERATIVE, INC., EAST KENTUCKY POWER COOPERATIVE, INC., ASSOCIATED ELECTRIC COOPERATIVE INC., BASIN ELECTRIC POWER COOPERATIVE, INC., and RAINBOW ENERGY CENTER, LLC,	)	**Case No. 24-1179 (consolidated with Case No. 24-1119)**
Petitioners,	)	
v.	)	
U.S. ENVIRONMENTAL PROTECTION AGENCY and MICHAEL S. REGAN, in his official capacity as Administrator of the U.S. Environmental Protection Agency,	)	
Respondents.	)	

PETITIONERS' MOTION FOR STAY OF THE FINAL RULE

(Counsel listed on inside cover)

Dated: June 21, 2024

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ORAL ARGUMENT NOT YET SCHEDULED

CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

Pursuant to Circuit Rule 28(a)(1), Petitioners National Rural Electric Cooperative Association, Lignite Energy Council, National Mining Association, Minnkota Power Cooperative, Inc., East Kentucky Power Cooperative, Inc., Associated Electric Cooperative Inc., Basin Electric Power Cooperative, and Rainbow Energy Center, LLC certify as follows:

A. Parties

Petitioners in these consolidated cases are:

- 24-1119: State of North Dakota, State of West Virginia, State of Alaska, State of Arkansas, State of Georgia, State of Idaho, State of Indiana, State of Iowa, State of Kansas, Commonwealth of Kentucky, State of Louisiana, State of Mississippi, State of Missouri, State of Montana, State of Nebraska, State of Oklahoma, State of South Carolina, State of South Dakota, State of Tennessee, State of Texas, State of Utah, Commonwealth of Virginia, and State of Wyoming.

- 24-1154: NACCO Natural Resources Corporation.

- 24-1179: National Rural Electric Cooperative Association, Lignite Energy Council, National Mining Association, Minnkota Power Cooperative, Inc., East Kentucky Power Cooperative, Inc., Associated Electric Cooperative Inc., Basin Electric Power Cooperative, and Rainbow Energy Center, LLC.

- 24-1184: Oak Grove Management Company, LLC and Luminant Generation Company LLC.

- 24-1190: Talen Montana, LLC.
- 24-1194: Westmoreland Mining Holdings LLC
- 24-1201: America's Power and Electric Generators MATS Coalition (Salt River Project Agricultural Improvement and Power District, Talen Energy Supply, LLC, and NorthWestern Energy Public Service Corporation).

Respondents are the United States Environmental Protection Agency ("EPA") and Michael S. Regan, in his official capacity as Administrator of EPA.

Intervenors for Petitioners in 24-1119 and all consolidated cases:

- San Miguel Electric Cooperative, Inc. in support of Petitioners.

Intervenors for Respondents in 24-1119 and all consolidated cases:

- Environmental and Public Health Organizations (Air Alliance Houston, Alliance of Nurses for Healthy Environments, American Academy of Pediatrics, American Lung Association, American Public Health Association, Chesapeake Climate Action Network, Citizens for Pennsylvania's Future, Clean Air Council, Clean Wisconsin, Downwinders at Risk, Environmental Defense Fund, Environmental Integrity Project, Montana Environmental Information Center, Natural Resources Council of Maine, Natural Resources Defense Council, the Ohio Environmental Council, Physicians for Social Responsibility, and Sierra Club)
- Commonwealth of Massachusetts, State of Minnesota, State of Connecticut, State of Illinois, State of Maine, State of Maryland, State of Michigan, State of New Jersey, State of New York, State of Oregon, State of Pennsylvania, State of

Rhode Island, State of Vermont, State of Wisconsin, District of Columbia, City of Baltimore, City of Chicago, City of New York in support of Respondents.

B. Rulings Under Review

The Final Rule entitled National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Generating Units Review of the Residual Risk and Technology Review. 89 Fed. Reg. 38,508 (May 7, 2024).

C. Related Cases

There are no additional cases pending in other U.S. Courts of Appeals challenging the same final action.

Dated: June 21, 2024

/s/Elizabeth C. Williamson
ELIZABETH C. WILLIAMSON

/s/ Carroll Wade McGuffey III
CARROLL WADE MCGUFFEY III

/s/Megan H. Berge
MEGAN H. BERGE

CORPORATE DISCLOSURE STATEMENTS

Pursuant to Federal Rule of Appellate Procedure 26.1 and Circuit Rule 26.1, Petitioners National Rural Electric Cooperative Association, Lignite Energy Council, National Mining Association, Minnkota Power Cooperative, Inc., East Kentucky Power Cooperative, Inc., Associated Electric Cooperative Inc., Basin Electric Power Cooperative, and Rainbow Energy Center, LLC, submit the following corporate disclosure statements:

National Rural Electric Cooperative Association ("NRECA") is the national association for nearly 900 not-for-profit rural electric cooperatives and public power districts that provide electric service to roughly one in eight Americans, covering 56% of the Nation's landmass. Rural electric cooperatives serve millions of businesses, homes, schools, farms, irrigation systems, and other establishments in 2,500 of the nation's over 3,100 counties, including 92% of the Nation's persistent poverty counties. America's electric cooperatives are owned by the people they serve, and they comprise a unique sector of the electric industry. Electric cooperatives are focused on providing affordable, reliable, and safe electric power in an environmentally responsible manner. NRECA is not a publicly held corporation, and NRECA has no parent corporation. No publicly held company has 10% or greater ownership interest in NRECA.

Lignite Energy Council ("LEC") is a regional, nonprofit organization whose primary mission is to promote the continued development and use of lignite coal as an energy resource. LEC's membership includes producers of lignite coal who have an ownership interest in and who mine lignite, users of lignite who operate lignite fired electric generating plants, and suppliers of goods and services to the lignite coal industry. LEC has no outstanding shares or debt securities in the hand of the public and has no parent company. No publicly held company has a 10% or greater ownership interest in LEC.

National Mining Association ("NMA") is a nonprofit national trade association that represents the interests of the mining industry, including every major coal company operating in the United States. NMA has over 280 members, whose interests it represents before Congress, the administration, federal agencies, the courts, and the media. NMA is a "trade association" within the meaning of Circuit Rule 26.1(b). NMA is not a publicly held corporation and has no parent corporation. No publicly held company has 10% or greater ownership interest in NMA.

Minnkota Power Cooperative, Inc. ("Minnkota") is a corporation organized under the laws of the State of Minnesota, and its corporate headquarters are located at 5301 32nd Avenue South, Grand Forks, North Dakota 58201. Minnkota is owned by 11 rural electric cooperatives: Beltrami Electric Cooperative, Cass County Electric Cooperative, Cavalier Rural Electric Cooperative, Clearwater-Polk Electric Cooperative, Nodak Electric Cooperative, North Star Electric Cooperative, PKM Electric Cooperative, Red Lake Electric Cooperative, Red River Valley Co-op Power, Roseau Electric Cooperative, and Wild Rice Electric Cooperative. No publicly held corporation owns 10% or more of Minnkota's stock.

East Kentucky Power Cooperative, Inc. ("East Kentucky") is a corporation organized under the laws of the Commonwealth of Kentucky, and its corporate headquarters are located at 4775 Lexington Road, Winchester, Kentucky 40392. East Kentucky is owned by 16 rural electric cooperatives: Big Sandy Rural Electric Cooperative, Blue Grass Energy Cooperative, Clark Energy Cooperative, Cumberland Valley

Electric, Farmers Rural Electric Cooperative, Fleming-Mason Energy Cooperative, Grayson Rural Electric Cooperative, Inter-County Energy, Jackson Energy Cooperative, Licking Valley Rural Electric Cooperative, Nolin Rural Electric Cooperative, Owen Rural Electric Cooperative, Salt River Electric Cooperative, Shelby Energy Cooperative, South Kentucky Rural Electric Cooperative, and Taylor County Rural Electric Cooperative. No publicly held corporation owns 10% or more of East Kentucky's stock. Associated Electric Cooperative Inc. is a corporation organized under the laws of the State of Missouri. Associated Electric Cooperative Inc. has no parent companies, non-wholly owned subsidiaries, or affiliates that have issued shares to the public.

Basin Electric Power Cooperative ("Basin Electric") is a cooperative corporation organized under the laws of the State of North Dakota, and its corporate headquarters are located at 1717 East Interstate Avenue, Bismarck, North Dakota 58503. Basin Electric is owned by 141 rural electric cooperatives. Its Class A members include: Central Montana Electric Power Cooperative, Central Power Electric Cooperative, Corn Belt Power Cooperative, Crow Wing Power, East River Electric Power Cooperative, Grand Electric Cooperative, KEM Electric

Cooperative, L&O Power Cooperative, Members 1st Power Cooperative, Minnesota Valley Cooperative Light & Power Association, Minnesota Valley Electric Cooperative, Mor-Gran-Sou Electric Cooperative, Northwest Iowa Power Cooperative, Rosebud Electric Cooperative, Rushmore Electric Power Cooperative, Tri-State Generation and Transmission Association, Upper Missouri Power Cooperative, Wright-Hennepin Cooperative Electric Association, Wyoming Municipal Power Agency. No publicly held company has 10% or greater ownership interest in Basin Electric.

Rainbow Energy Center, LLC ("Rainbow") is a North Dakota limited liability company, is a wholesale power generation company headquartered in Bismarck, North Dakota. Rainbow is a wholly owned subsidiary of REMC Assets, LP, a North Dakota limited partnership. REMC Group, LLC, a North Dakota limited liability company, holds the 1% general partner controlling interest in REMC Assets, LP. No publicly held corporation has a 10% or greater ownership interest in REMC Assets, LP or in REMC Group, LLC.

Dated: June 21, 2024

/s/Elizabeth C. Williamson
ELIZABETH C. WILLIAMSON

/s/ Carroll Wade McGuffey III
CARROLL WADE MCGUFFEY III

/s/Megan H. Berge
MEGAN H. BERGE

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GLOSSARY

2020 MATS Review	85 Fed. Reg. 31,286 (May 22, 2020)
ACI	Activated Carbon Injection
CAA	Clean Air Act, 42 U.S.C. §§ 7401 to 7671q
CEMS	Continuous Emission Monitoring Systems
Cichanowicz Report	Cichanowicz, *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, EPA-HQ-OAR-2018-0794-5956
EGUs	Electric Source Generating Unit
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
FF	Fabric Filter
fPM	Filterable Particulate Matter
HAP	Hazardous Air Pollutant
Final Rule	*National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Generating Units Review of the Residual Risk and Technology Review.* 89 Fed. Reg. 38,508 (May 7, 2024)
LEC Comments	Comment from Jason Bohrer, Lignite Energy Council (June 23, 2023) Doc. ID EPA-HQ-OAR-2018-0794-5957
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards

NMA	National Mining Association
PAC	Powdered Activated Carbon
Risk Assessment	*Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019)

LIST OF ATTACHMENTS

Exhibit 1	Declaration of Stacy L. Tschider, *Chief Executive Officer, Rainbow Energy Center, LLC*
Exhibit 2	Declaration of Craig Courter, *General Manager, San Miguel Electric Cooperative, Inc.*
Exhibit 3	Declaration of Robert McLennan, *President & Chief Executive Officer, Minnkota Power Cooperative*
Exhibit 4	Declaration of Jerry Purvis, *Vice President, Environmental Affairs, East Kentucky Power Cooperative, Inc.*
Exhibit 5	Declaration of Gavin A. McCollam, *Senior Vice President & Chief Operating Officer, Basin Electric Power Cooperative*
Exhibit 6	Declaration of Mike Holmes, *Vice President, Lignite Energy Council and Director and Technical Advisor for North Dakota's Lignite Research, Development and Marketing Program*
Exhibit 7	Declaration of Christopher D. Frietz, *Vice President-Land, Associate General Counsel & Assistant Secretary, NACCO Natural Resources Corporation*
Exhibit 8	Declaration of Tawny Bridgeford, *General Counsel & Senior Vice President, Regulatory Affairs, National Mining Association*
Exhibit 9	Declaration of Jason Bohrer, *President and Chief Executive Officer, Lignite Energy Council*
Exhibit 10	Declaration of Russell Raad, *President, Abrasives, Inc.*

Exhibit 11	*National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Generating Units Review of the Residual Risk and Technology Review.* 89 Fed. Reg. 38,508 (May 7, 2024)

INTRODUCTION

This case is a textbook example of unlawful administrative action. EPA boldly finds the necessity to regulate, armed only with thinly supported, biased, and flawed technical analyses. In doing so, EPA ignored completely the results of its own comprehensive assessment showing no health risks remain. To justify its unreasonable conclusion, EPA claims revisions are necessary because of "developments in practices, processes, and control technologies." Yet EPA's purported "developments" are a mirage, fabricated via a re-analysis that (1) does not constitute a "development" and (2) is wrong.

Immediate harm is at stake. Petitioner utilities must expeditiously cipher a path for compliance by initiating lengthy and expensive control projects or preparing to shutdown. The repercussions will be vast. Grid reliability will further decline. Acute economic pressure will intensify for communities dependent on lignite mining. Small utilities and the rural, cost-sensitive communities they serve will be particularly exposed. Meanwhile, this source category of electricity generating units ("EGUs") pose no meaningful health or environmental risks from hazardous air pollutant ("HAP") emissions. The existing Mercury and Air Toxics

Standards ("MATS") regulations succeeded so thoroughly that the level of risk remaining even suggests *de*regulation may be appropriate. Nevertheless, EPA turned a blind-eye to this crucial factor in evaluating whether revisions are "necessary."

Petitioners ask this Court to grant a stay to avoid repeating history. In 2015, the United States Supreme Court found the original MATS unlawful. But without a stay, the rule had already forced every unit to incur compliance costs or retire. In fact, in a press interview, then-EPA Administrator McCarthy boasted that the ruling would not matter because "[m]ost of [the regulated facilities] are already in compliance, [and] investments have been made." Timothy Cama & Lydia Wheeler, *Supreme Court Overturns Landmark EPA Air Pollution Rule*, THE HILL (June 29, 2015). By the time Petitioners prevail on the merits, the rule will have forced regulated entities to make irreversible decisions and irrecoverable investments to comply. These harms are certain to occur, regardless of the decision in this case, unless this Court grants a stay.

STATEMENT OF THE CASE

I. LEGAL AND REGULATORY BACKGROUND

Section 112 of the Clean Air Act ("CAA") authorizes EPA to regulate HAPs from "stationary sources." *See Michigan v. EPA*, 576 U.S. 743, 747-

48 (2015). To do so, EPA must publish a list of "categories and subcategories" of HAP emission sources. 42 U.S.C. §7412(c). Then, for such "listed" source categories, EPA must promulgate HAP emission standards. *Id.* §7412(d)(1). However, before EPA can "list" EGUs, the statute requires EPA to conduct "a study of the hazards to public health" from EGU HAP "after imposition of the requirements of [the CAA]," and determine that the regulation of EGU HAP "is appropriate and necessary." *Id.* §7412(n)(1)(A).

EPA's HAP standards are referred to as maximum achievable control technology ("MACT") standards because they "shall require the maximum degree of reduction in emissions of [HAP]" after "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." *Id.* §7412(d)(2). For existing sources, the MACT standards must be at least as stringent as "the average emission limitation achieved by the best performing 12 percent of the existing sources" in the applicable category or subcategory. *Id.* §7412(d)(3)(A)-(B). This minimum level of stringency is known as the "MACT floor." *See Michigan*, 576 U.S.at 748-49. EPA may adopt standards that are more stringent than the floors, known as "beyond-the-floor standards," *id.*, but only after "consider[ing] cost (alongside other specified factors)." *Id.* (citing 42 U.S.C. §7412(d)(2)).

For MACT standards, EPA must conduct a one-time "residual" risk analysis eight years after a final standard is promulgated. 42 U.S.C. §7412(f)(2). In addition, the CAA also requires EPA review its standards every eight years and revise those standards "as necessary." *Id.* §7412(d)(6). Section 112(d)(6) includes a parenthetical requiring EPA to "take[] into account developments in practices, processes, and control technologies." *Id.* EPA can de-list a source category upon finding that no source in the category presents a lifetime risk of cancer greater than 1-in-1 million to the most exposed individual. *Id.* §7412(c)(9)(B).

II. EPA PROMULGATES THE MATS RULE IN 2012

In December 2000, EPA determined that regulating coal- and oil-fired EGUs was "appropriate and necessary." 65 Fed. Reg. 79,825, 79,826 (Dec. 20, 2000). In February 2012, the agency promulgated the MATS Rule, which "reaffirmed [EPA's] appropriate-and-necessary finding." *Michigan*, 576 U.S. at 749 (citing 77 Fed. Reg. 9,304, 9,330 (Feb. 16, 2012)). Specifically, EPA stated that regulating EGU HAP was "'necessary' because…impos[ing]…the Act's other requirements did not eliminate these risks." *Id.* (quoting 77 Fed. Reg. at 9,363). The MATS Rule established MACT emissions standards for mercury and other HAP emissions from coal- and oil-fired EGUs.

Relevant to this case, in adopting the MATS Rule, EPA recognized that EGUs firing lignite coal cannot meet the same limits as EGUs firing other coal types. In fact, EPA's analysis indicated the MACT floor for lignite was nearly ten times higher than for other coals. *See MACT Floor Analysis - Revised*, EPA-HQ-OAR-2009-0234-9858, at 12, 19, 144 (May 18, 2011). However, EPA established a "beyond-the-floor" standard for lignite based on the highest level of emission control deemed achievable by the single best performing lignite unit, 77 Fed. Reg. at 9,369, the level of stringency typically applied only to new sources, 42 U.S.C. §7412(d).

Numerous parties successfully challenged MATS, arguing EPA erred by refusing to consider the substantial costs the rule would impose on the already heavily regulated power sector. *See Michigan*, 576 U.S. at 747-50. The U.S. Supreme Court agreed, holding EPA should have considered cost in determining whether it was "appropriate" to regulate EGU HAP, reasoning cost to regulated parties is a "centrally relevant factor" in the "appropriate and necessary" analysis. *Id.* at 752-53, 760.

III. EPA REVIEWS THE MATS RULE IN 2020

In 2020, eight years after adopting the original MATS Rule, EPA timely completed the Section 112(f)(2) review of risk and the Section 112(d)(6) review of whether revisions are "necessary." 85 Fed. Reg. 31,286 (May 22, 2020) ("2020 MATS Review").

The risk review involved a comprehensive and complex dispersion and health risk modeling analysis of every individual covered EGU in the country. With that analysis, EPA determined the maximum individual excess cancer risk associated with *any* single EGU was 9-in-1 million, well below the presumptively acceptable risk level of 100-in-1 million. 85 Fed. Reg. at 31,316; *see Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019) ("*Risk Assessment*"). However, the maximum level of 9-in-1 million risk identified was associated with a single, uncontrolled, oil-fired unit in Puerto Rico. *See* 85 Fed. Reg. at 31,319. Moreover, for ***coal***-EGUs (including all lignite EGUs), the highest risk identified was 0.3-in-1 million. *See Risk Assessment,* App. 10, Tbls. 1 & 2a. Based on these results, EPA concluded revisions to the 2012 MATS rule were not "necessary." 85 Fed. Reg. at 31,314. Further, to comply with its Section 112(d)(6) obligation to "tak[e] into account" new "developments" in determining whether revisions were "necessary," EPA evaluated the "practices, processes, and control technologies" available in 2020, but found nothing had changed since MATS was first adopted. *Id.* at 31,218.

IV. EPA RECONSIDERS ITS 2020 REVIEWS AND REVISES MATS TO IMPOSE FAR MORE STRINGENT STANDARDS

In response to Executive Order 13990 dictating reconsideration of the 2020 MATS Review, EPA issued proposed revisions to MATS in April 2023. 88 Fed. Reg. 24,854 (April 24, 2023). Despite receiving highly critical comments questioning the achievability of the proposed standards, EPA issued the Final Rule without significant changes. 89 Fed. Reg. 38,508 (May 7, 2024). EPA's 2023 re-review contained two components. First, EPA affirmed the conclusions of its 2020 risk review, finding all modeled HAP exposures to be well below acceptable risk thresholds. Nevertheless, EPA changed its mind and decided revisions to MATS were "necessary" under Section 112(d)(6).

Claiming to have found new "developments," EPA lowered the surrogate filterable particulate matter ("fPM") standard by 66% and required sources to demonstrate compliance with that new lower standard using continuous emission monitoring systems ("CEMS") instead of quarterly stack tests. *See* 89 Fed. Reg. at 38.,509-10. EPA also decided that all lignite EGUs can meet the same mercury standard imposed on EGUs firing other coal types, and therefore lowered the "beyond-the-floor" mercury standard for the lignite subcategory by 70%—contrary to its 2012 conclusion. *Id.* at 38,510.

STANDARD FOR GRANTING A STAY

This Court may stay an agency rule from taking effect after considering four factors: (1) the likelihood that the moving party will prevail on the merits of its claim; (2) the risk that the moving party will suffer irreparable harm absent a stay; (3) the prospect that nonmoving parties will suffer irreparable harm if the Court grants the stay; and (4) the public's interest in granting a stay. *Nken v. Holder*, 556 U.S. 418, 434 (2009). The nonmovants' harm and the public's interest "merge when the Government is the opposing party." *Id.* at 435.

REASONS FOR GRANTING A STAY

I. PETITIONER HAS A HIGH LIKELIHOOD OF SUCCESS ON THE MERITS

A. EPA VIOLATED THE CAA BY REVISING MATS WITHOUT ANY "DEVELOPMENTS."

The CAA requires EPA to revise MACT standards "as necessary," and provides for consideration of "developments in practices, processes, and control technologies" in that review. Such "developments" in fPM and mercury control have not occurred. *See* 89 Fed. Reg. at 38,518. Therefore, EPA lacks the statutory authority to revise the standards in the Final Rule. *See* 42 U.S.C. § 7412(d)(6).

Both this Court and EPA have routinely concluded that only concrete technological developments may support a decision to revise a standard. Past reviews demonstrate the type of control technology developments that may support a decision to revise a standard. In *National Association for Surface Finishing v. EPA*, this Court found EPA had identified clear developments supporting a revised hexavalent chromium standard, including "emissions elimination devices, HEPA filters, enclosing tank hoods, and fume suppressants." 795 F.3d 1, 11 (D.C. Cir. 2015). While the Court recognized EPA did not have to identify a "nexus between each distinct development and the revised standards," it agreed EPA could not revise a standard without establishing "pertinent 'developments' [have] occurred." *Id.* The Court also emphasized EPA must assess the "cost and feasibility of [those] developments." *Id.* at 5. Other reviews in which EPA revised HAP standards likewise identified concrete developments. *See, e.g.*, 69 Fed. Reg. 48,338, 48,351 (Aug. 9, 2004) (new work practices to control "door leaks and topside leaks" from coke oven batteries); 77 Fed. Reg. 556, 569 (Jan. 5, 2012) (the use of battery breakers to separate plastics from automotive batteries and enclosures to control fugitive emission sources).

Here, the technical record is clear. The primary fPM control technology used today (electrostatic precipitator ("ESP") technology) has "not undergone fundamental changes since 2011." 89 Fed. Reg. at 38,530. The record also identifies no developments in fPM Fabric filter ("FF") control performance at all. *Id.* (only identifying changes in maintenance costs). Likewise, lignite EGUs use activated carbon injection ("ACI"), as they did in 2011 when EPA first proposed MATS. The Final Rule praises the effectiveness of brominated powdered activated carbon ("PAC"), but this product was available and relied upon when the original Hg standard was set. EPA provides no basis for claiming any of these technologies are brand-new developments in "practices, processes, [or] control technologies." 42 U.S.C. § 7412(d)(6).

Lacking any concrete developments, EPA assumes developments must exist simply because some facilities have over-complied. But EPA's data analysis is not itself a "development," and EPA's approach is inconsistent with the statute. Namely, EPA's reliance on compliance data to establish a revised standard is similar to setting a new MACT floor. However, Section 112(d)(6) does not authorize EPA to reset the MACT floor by analyzing data. EPA itself understands that resetting the floor is inappropriate. 71 Fed. Reg. 27,324, 27,327 (May 10, 2006) ("requiring additional floor determinations could effectively convert existing source standards into new source standards"). EPA's substitution of compliance data for an actual "development" in control practices creates a backdoor to reset the MACT floor.

B. THE FINAL RULE IS ARBITRARY AND CAPRICIOUS BECAUSE ITS TECHNICAL FOUNDATIONS ARE FATALLY FLAWED.

Unsalvageable and unreliable fPM and mercury data analyses underpin the Final Rule. EPA must "reach[]" its result applying "logic[] and rational[e]." *Allentown Mack Sales & Serv., Inc. v. N.L.R.B.*, 522

U.S. 359, 374 (1998). Data analyses cannot rely on "faulty data" so as to exceed the boundaries of permissible agency action. *See Nat. Res. Def. Council v. EPA*, 529 F.3d 1077, 1086 (D.C. Cir. 2008).

Here, the technical analyses in the docket illuminate the many errors EPA committed. *See* Cichanowicz, *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology* (June 19, 2023), Doc. ID EPA-HQ-OAR-2018-0794-5956 ("Cichanowicz Report").

First, the fPM analysis for the Final Rule is defective because it cherry-picks fPM data from quarters with the lowest emission rates that units had historically achieved (using one or two of the lowest samples for approximately 80% of units). *See id.* at 1, 10. Claiming to use data from a five-year period, EPA actually relied on "variable" quarters from just three years, without explaining the gaps and inconsistencies that bias the analysis. *Id.* at 6-9. This "best of the best" dataset does not yield continuous rates that units can meet under all seasonal and load conditions. *See id.* at 11. Further, the fPM analysis falters by failing to exclude periods where units were co-firing natural gas (which is not indicative of the source category), 89 Fed. Reg. at 38,538, and ignoring variability in individual EGU configuration and fPM emissions performance. EPA also undercounts the units requiring fPM retrofits by failing to apply an appropriate "design and operating margin." Cichanowicz Report at 21.

Finally, EPA drastically underestimates the cost associated with those retrofits. *See* 89 Fed. Reg. at 38,521-22; Cichanowicz Report at 14-17; Sargent & Lundy, *Particulate & Mercury Control Technology Evaluation & Risk Assessment for Proposed MATS Rule Report*, EPA-HQ-OAR-2018-0794-5978, at 3-7 (June 23, 2023). By calculating the appropriate number of fPM retrofits (50% more than the Final Rule), the capital costs and operation and maintenance costs (on par with real projects) total three-times the cost of EPA's estimate. Cichanowicz Report at 21 ("annual cost of $1.96 B versus EPA's estimate of 633 M/yr").

Second, regarding the mercury standard, EPA gutted the original "beyond-the-floor" limit for lignite units by 70% without any verified testing or evidence that demonstrates lignite units can meet the new mercury limitation of 1.2 lb/TBtu. EPA assumes units will continue to use ACI with the same brominated PAC available in 2015 to achieve reductions "greater than 90 percent." 89 Fed. Reg. at 38,547. EPA relies on the "Beyond-the-Floor Memorandum" from its 2012 MATS Rule for this key 90% assumption. *See id.* That Memorandum relies on a single trade publication that presents data results from just *one* lignite unit. This single unit is EPA's only basis for assuming 90% removal is achievable nationwide. Without more, this conclusion cannot withstand scrutiny.

EPA's error is revealed by its reliance on performance data from a lignite unit with an annual rate of 1.33 lb/TBtu (2021) and 1.73 lb/TBtu (2022) to "clearly demonstrate the achievability of the proposed 1.2 lb/TBtu emission standard by lignite-fired EGUs." *Id.* at 38,540. Although EPA identifies one facility that demonstrated average mercury emission rates below 1.2 lb/TBtu in 2022, *see id.,* that unit is an outlier. It is the newest lignite unit and utilizes controls that are not technically feasible on many other lignite-fueled facilities. Comment from Jason Bohrer, Lignite Energy Council ("LEC Comments"), EPA-HQ-OAR-2018-0794-5957, at 8 (June 23, 2023). Plainly, the Final Rule has not met the D.C. Circuit's meaning of "achievable" as "capable of being met under most adverse conditions which can reasonably be expected to recur."

White Stallion Energy Center, LLC v. EPA, 748 F.3d 1222, 1251 (2014), *rev'd sub nom. Michigan v. EPA*, 576 U.S. 743 (2015) (internal quotation marks and citation omitted).

Moreover, EPA cannot claim to have fairly evaluated cost of compliance when it has failed to demonstrate compliance is even achievable. EPA's estimate is based on a calculation of how much more brominated PAC a hypothetical unit might need. That estimate depends entirely on the unproved assumption that adding more PAC will drive emissions down to 1.2 lb/TBtu, which remains in significant doubt. EPA further errs by assuming that lignite units can use their existing ACI systems to inject massive quantities of PAC without any equipment modifications. No evidence or data backs these hypotheses. EPA's analysis has no correlation to the feasibility or real costs to comply with a limitation of 1.2 lb/Tbtu.

Ultimately, and arbitrarily, EPA extraordinarily concludes that the data justifies an identical standard for lignite and non-lignite units. But the gaps in analysis and selective data indicate EPA worked backwards to support its preference for a uniform standard. Accordingly, EPA did not "reach[]" its result applying "logic[] and rational[e]." *Allentown*, 522 U.S. at 374.

C. REGARDLESS OF ANY "DEVELOPMENTS," EPA HAS NOT DEMONSTRATED REVISED STANDARDS ARE "NECESSARY."

By focusing solely on supposed "developments," EPA unlawfully limited the scope of its review of MATS under Section 112(d)(6). That section, in its entirety, reads as follows:

> (6) Review and revision. The Administrator shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years.

The phrase "as necessary" controls and authorizes EPA to consider all relevant factors, taking into account the statutory design and goals. *See GTE Serv. Corp. v. F.C.C.*, 205 F.3d 416, 423 (D.C. Cir. 2000) ("[A] statutory reference to 'necessary' must be construed in a fashion that is consistent with the ordinary and fair meaning of the word, *i.e.*, so as to limit 'necessary' to that which is required to achieve a desired goal."). Black's Law Dictionary (11th ed. 2019) defines "necessary" as "needed for some purpose or reason; essential."

While Section 112(d)(6) offers a "non-exhaustive list of considerations," in the form of its parenthetical clarification that EPA must consider "practical and technological advances," "the operative standard is 'revise as necessary.'" *La. Env't Action Network v. EPA*, 955 F.3d 1088, 1097-98 (D.C. Cir. 2020); s*ee also Surface Finishing*, 795 F.3d at 5. EPA itself has previously acknowledged that it must consider other factors in its "necessary" analysis, including the relative costs and benefits of regulation. *See* 82 Fed. Reg. 40,970, 40,975, 40,977-78 (Aug. 29, 2017) (declining to lower the standard, despite developments in control technology, because the source category "already achieved approximately 95-percent reduction in formaldehyde emissions" and industry emissions were trending lower); 69 Fed. Reg. at 48,351 (recognizing existing standards "provide an ample margin of safety to protect public health and prevent adverse environmental effects, [meaning] one can reasonably question whether further reviews of technological capability are 'necessary'").

Here, EPA improperly failed to consider key factors in determining that a revision to MATS was necessary. Chief among the factors EPA claims it must ignore include its own risk assessment, which confirms

EGU HAP present infinitesimal risks. For coal EGUs—the only units in the source category subject to EPA's rule revisions—the risk of HAP is now just one-third of the 1-in-1 million level of risk at which Congress authorized EPA to cease regulating. 42 U.S.C. §7412(c)(9)(B)(i); 89 Fed. Reg. 38,516-18. Nothing in Section 112(d)(6) directs EPA to ignore such compelling evidence, or the basic administrative law principles requiring agency decisions to be made in full view of all relevant facts. *See FCC v. Prometheus Radio Project*, 592 U.S. 414, 423 (2021); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

EPA's abrupt change of position underscores the arbitrariness of its decision. The Final Rule rests on the *same* factual findings that underlay its contradictory determination from 2020. In 2020, EPA followed the science of its own risk assessment and determined more stringent standards under MATS were unnecessary. *See* 88 Fed. Reg. at 24,866. No data or technology has changed since 2020 to warrant EPA's reversal.

The reasoning underlying the U.S. Supreme Court's decision in *Michigan v. EPA* supports this conclusion. In *Michigan*, the Court considered whether EPA had to consider cost in determining, under

Section 112(n)(1)(A), whether regulating EGU HAP was "appropriate and necessary." Although cost was not listed as a relevant factor in the statute, the Court concluded cost was "centrally relevant" to that question. 576 U.S. at 752-53, 760. In fact, the Court opined "[o]ne does not need to open up a dictionary in order to realize the capaciousness of this phrase ['appropriate and necessary']." *Id.* at 752.

In *Michigan*, the Court directed EPA to consider all "advantages and…disadvantages" of regulation unless Congress clearly limited the scope of the Agency's focus. *Id.* at 753. Citing precedent on this unremarkable principle of law, the Court opined "[o]ne would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Id.* at 752. If irrational ignorance to costs and benefits would not be "appropriate" under Section 112(n), it certainly cannot be "necessary" under Section 112(d)(6).

II. PETITIONERS AND THEIR MEMBERS WILL SUFFER IMMEDIATE, IRREPARABLE HARM FROM ENFORCEMENT OF THE FINAL RULE

Petitioners will suffer substantial, irreparable, and immediate harm if this Court does not stay the Final Rule. *Texas v. EPA*, 829 F.3d

405, 433 (5th Cir. 2016) (finding that compliance with an agency action "later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs." (internal quotation marks and citation omitted)); *Phillip Morris USA Inc. v. Scott*, 561 U.S. 1301, 1304 (2010) (Scalia, J., in chambers) ("If expenditures cannot be recouped, the resulting loss may be irreparable."). Absent a stay, Petitioners will suffer the following harms.

First, Petitioner utilities must immediately embark on substantial and expensive fPM emissions control projects to bridge the gap between the prior standard (0.030 lb/mmBtu) and the unprecedented new fPM standard (0.010 lb/mmBtu). Tschider Decl. ¶16. Some units must also install PM CEMS. *Id.* ¶15. Many units cannot meet the new fPM limit with their existing ESPs. Courter Decl. ¶12 ("not achievable"). To achieve a minute amount of fPM reductions, existing ESPs must be entirely rebuilt. McLennan Decl. Table B ($38,452,000 for ESP rebuild). ESP retrofit projects may improve fPM emissions control but may not achieve sufficient reductions. Further, some ESPs do not have a viable retrofit option due to unit configuration, equipment spacing, or original ESP design constraints. Courter Decl. ¶29. The only other option is replacement with a FF—a massive capital expenditure. *See id.* ¶29 (up to $20.7 million per year in 2024 dollars); McLennan Decl. Table B ($246,812,000 total).

Some FFs also cannot achieve the new fPM limitation. They were not originally designed to meet such an extremely low fPM limitation. Purvis Decl. ¶24 ("[T]he 2005-vintage baghouse…was not designed to meet 0.010 lb/mmBtu."). As a result, these FFs will see downtime on a regular basis, despite best engineering and maintenance practices. *Id.* ¶25 ("[A] single hole the size of a human pinky finger in one of over 8,000 fabric filter bags…can [exceed] the new standard").

Second, the new mercury standard is not demonstrably achievable. McLennan Decl. ¶32 ("[R]ecent testing results demonstrate that MRY is unable to achieve the New Mercury Limitation," referring to Attachment A, Sargent & Lundy, *Mercury Testing Results for the MATS Residual Risk and Technology Review*, at 3-5 (May 22, 2024)); McCollam Decl. ¶30 ("no evidence that the units…could achieve compliance…on a sustained basis"); Courter Decl. ¶21 ("[T]he 1.2 lb/TBtu in the MATS Rule…is not feasible and…not supported by the data."). Given this uncertainty, significant testing must occur, at a substantial cost to utilities, to determine achievable mercury reductions. Holmes Decl. ¶7; McLennan Decl. ¶37 (testing costs exceed $600,000); McCollam Decl. ¶48. If the new mercury standard cannot be met, units must retire at a substantial cost. Noncompliance is not an option. McLennan Decl. ¶37.

Third, even if the mercury standard is achievable, lignite units must replace or substantially retrofit their existing ACI systems with redesigned ACI systems that can inject much greater quantities of PAC. The cost of retrofits and replacements alone are upwards of $5 million dollars. Tschider Decl. ¶¶12-14 (estimating "approximately $5 million to install an activated carbon injection system" and $2.4 million annually in operating costs); McLennan Decl. Table A ($13.7 million in total expenses for entire control system, with continuing annual expenses); McCollam Decl. ¶34 ("modification costs and ongoing operation expenses are significant…over $4,000,000 in capital expenditures upfront").

Fourth, if a unit determines the Final Rule's emission requirements are not technologically or commercially feasible, its only option is to retire prematurely. *See* McLennan Decl. ¶¶62, 70-74; Holmes Decl. ¶¶7, 8-10; Friez Decl. Attach. A at 3. Moreover, the sheer cost of installing or upgrading fPM and/or mercury controls will drive retirements. McLennan Decl. ¶74. Without generation, utilities must purchase power at unsustainable prices to meet demand. Purvis Decl. ¶25 (up to $31 million to replace Unit 3 for a 7-day forced outage); McLennan Decl. ¶75 ($236,888,000 for 4 days of replacement power).

Fifth, forced retirement of these units will devastate mines that supply them. The harm will be particularly severe in North Dakota, where lignite coal is sourced adjacent to generating units and conversion facilities in "mine-to-mouth" operations that leave the mines without reasonable or viable market alternatives if an associated unit closes. Bridgeford Decl. ¶¶8-10; Bohrer Decl. ¶¶10, 21. Coal mines would be shuttered, stranding hundreds of millions of dollars of investment, s*ee* Friez Decl. ¶¶5, 7, 8, 13, 20, 22., and devastating businesses and industries that rely on mining, *see* Raad Decl. ¶¶6-9.

Sixth, grid reliability will decline. The North American Electric Reliability Corporation has already predicted grid shortfalls. McLennan Decl. ¶64; McCollam Decl. ¶47. Demand for electricity is increasing. Purvis Decl. ¶7. Contemporaneously, EPA dramatically underestimates the reliability impacts of the Final Rule. McCollam Decl. ¶45 ("[I]mpacts affect the ability of North Dakota utilities to maintain adequate generation resources."). Given the number of units that cannot comply with Final Rule's limitations, retirements are inevitable.

In summary, the nonrecoverable costs associated with installing and operating technology to meet the new fPM and mercury standards will be exorbitant. McLennan Decl. Table C (more than $260 million to comply with the Final Rule); Courter Decl. ¶29 (up to $21.1 million for the mercury standard, $20.7 million for the fPM standard, and $211,000 for PM CEMS, total levelized cost per year); Holmes Decl. ¶10; Tschider Decl. ¶24; Friez Decl. ¶¶16-17; McCollam Decl. ¶¶32-35; Purvis Decl. ¶11. The premature shutdown of plants will cause electricity costs to skyrocket.

Crucially, these harms will be immediate. If compliance is even feasible, the engineering, design, permitting procurement, sourcing, and installation necessary to comply with the Final Rule would require ***immediate*** expenditures to accommodate the long lead time for these processes. McCollam Decl. ¶¶34, 37-38 (36 months for ESP upgrades; 48 months for baghouse installation); McLennan Decl. ¶¶32-39, 51-52 (same); Purvis Decl. ¶¶34-36 (same); Tschider Decl. ¶¶10-11, 13-14; Friez Decl. ¶¶16-17, 23; Holmes Decl. ¶10. Generators will also need to make immediate, nonrecoverable investments in expensive testing and updated control technology. McCollam Decl. ¶34; McLennan Decl. ¶¶50, 54-55; Purvis Decl. ¶¶19, 22-23, 34-35. Utilities will be forced to close, forcing the mines that serve them to close as well, if these expenses are not shouldered. *See* Holmes Decl. ¶10; McCollam Decl. ¶25; McLennan Decl. ¶74; Bridgeford Decl. ¶8-10; Friez Decl. ¶¶5, 7, 8, 13, 20, 22; Raad Decl. ¶¶6-9. By the time the court can hold the Final Rule invalid, it will be too late to reverse course.

In fact, the 2012 MATS Rule was not stayed pending review; thus, power plants were forced to comply with that rule while challenging it in court, thereby incurring substantial nonrecoverable compliance costs and "caus[ing] a wave of coal unit retirements." *See* Comment from Bruce Watzman, National Mining Association ('NMA") EPA-HQ-OAR-2009-0234-20531, at 2 (Jan. 15, 2016). By the time the Supreme Court determined EPA acted "unreasonably," *see Michigan*, 576 U.S. at 752-60, the damage was done. A stay is necessary now to ensure history does not repeat itself.

III. ALL OTHER EQUITABLE CONSIDERATIONS FAVOR A STAY

The balance of equities and public interest weigh firmly in favor of a stay. *See Nken*, 556 U.S. at 434. Given Petitioners' likelihood of success in showing the Final Rule is arbitrary and capricious, the public has a strong interest in staying the Final Rule while this Court decides the merits of Petitioners' claims. *League of Women Voters of U.S. v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) ("no public interest in the perpetuation of unlawful agency action").

A stay of the Final Rule will harm neither EPA nor the public, where the Final Rule's heightened compliance obligations provide no appreciable public health benefits. EPA has exhaustively evaluated the risks from HAP emissions by every single coal-fired power plant in the nation and found the risks are well below acceptable levels with an ample margin of safety. *See supra* 13-14; LEC Comments at 1.

In contrast, the public will suffer harm absent a stay. Grid failures will negatively impact health and morbidity, and cause economic loss due to business closures, food spoilage, and property damage. Purvis Decl. ¶31 ("documented health impacts and morbidity" during Winter Storm Elliot); McLennan Decl. ¶67. Communities will also be harmed by job loss from shuttered generating units, associated mines, and ancillary businesses. Holmes Decl. ¶10; Friez Decl. ¶¶5, 7, 13, 20, 22 (anticipating the loss of more than 1,000 jobs); Bridgeford Decl. ¶8-10; Raad Decl. ¶¶9-11; McLennan Decl. ¶68 ("Minnkota employs approximately 200 people in the vicinity of Center, North Dakota" and the neighboring mine, BNI, "employs approximately 178 persons at the mine"); Courter Decl. ¶41 (consequences to local employment, contractors, local taxes, support of numerous businesses in rural Atascosa County). These forced shutdowns will also wreak havoc on regional economies, causing a significant loss of tax revenue and economic activity. Friez Decl. ¶14; McLennan Decl. ¶66; Raad Decl. ¶¶10-11.

Small entities will be most impacted. Courter Decl. ¶38 ("[C]urrent debt obligations and exorbitant compliance costs will cause extreme financial burdens on ratepayers."); Purvis Decl. ¶28. Rural communities are the most vulnerable to costs. Purvis Decl. ¶8 ("[F]amilies are literally faced with a daily choice between food, electricity, and medicine."); Courter Decl. ¶42 ("[R]atepayers live at or near the poverty level and cannot afford even modest increases in their electric bills."); Holmes Decl.

¶10; McLennan Decl. ¶¶63-68; McCollam Decl. ¶35 ("higher electricity prices" cannot be recouped).

CONCLUSION

For these reasons, this Court should grant Petitioners' Motion For Stay.

Dated: June 21, 2024

Respectfully Submitted,

/s/Elizabeth C. Williamson

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CERTIFICATE OF COMPLIANCE

Pursuant to Federal Rule of Appellate Procedure 32(g), I certify the following:

1. This Motion complies with the type-volume limitation of Federal Rule of Appellate Procedure 27(d)(2)(A) because this Motion contains 5,132 words, excluding the parts of the Motion exempted by Federal Rule of Appellate Procedure 32(f) and Circuit Rule 32(e)(1).

2. This Motion complies with the typeface requirements of Federal Rule of Appellate Procedure 32(a)(5) and the type style requirements of Federal Rule of Appellate Procedure 32(a)(6), because this brief has been prepared in a proportionately spaced typeface using Microsoft Word in 14-point Century Schoolbook font.

3. In accordance with Federal Rule of Appellate Procedure 18(a)(1) and Circuit Rule 18(a)(1), on June 20, 2024, Petitioners requested relief from EPA in a Petition For Stay of EPA's Final Rule. EPA has not acted on that request, and Petitioners now seek a stay from this Court. *See* D.C. Cir. R. 18(a)(1).

4. In accordance with Circuit Rule 18(a)(2), on June 21, 2024, counsel for Petitioners notified Respondents' counsel by email of

Petitioners' intent to file this Motion For Stay. Respondents oppose this Motion.

Dated: June 21, 2024

/s/Elizabeth C. Williamson
ELIZABETH C. WILLIAMSON

/s/Carroll Wade McGuffey III
CARROLL WADE MCGUFFEY III

/s/Megan H. Berge
MEGAN H. BERGE

CERTIFICATE OF SERVICE

I certify that on this 21st day of June, 2024, a copy of the foregoing motion was served electronically through the Court's CM/ECF system on all registered counsel.

Dated: June 21, 2024

/s/Elizabeth C. Williamson
ELIZABETH C. WILLIAMSON

/s/Carroll Wade McGuffey III
CARROLL WADE MCGUFFEY III

/s/Megan H. Berge
MEGAN H. BERGE

Exhibit 1

DECLARATION OF STACY L. TSCHIDER

1. I am the Chief Executive Officer for Rainbow Energy Center, LLC ("Rainbow"). As CEO, I oversee and direct all aspects of operations and development at Rainbow. Rainbow is the owner and operator of Coal Creek Station, a 1,151 MW lignite coal-fired power plant near Underwood, North Dakota, and participates in the Midcontinent Independent System Operator ("MISO") market as an Independent Power Producer. I provide this declaration in support of the motion to stay the rule promulgated on April 25, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency") and officially published in the *Federal Register* on May 7, 2024. *See* National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38,508 (May 7, 2024) ("Final Rule").

2. The Final Rule requires that Rainbow install costly, duplicative, and unnecessary controls at its Coal Creek Station coal-fired power plant. First, installation of controls to comply with emission limits for mercury ("Hg") and the newly required particulate matter continuous emission system ("PM CEMS") to monitor filterable particulate matter ("fPM") emissions will require immediate costly capital expenditures. Second, the fPM emission rate required by the Final Rule cannot be maintained under all operating conditions, putting Rainbow at risk of being unable to demonstrate compliance through the newly required use of PM

CEMS. Third, in accordance with EPA's Section 111(d) Guidelines, Rainbow is working to install full-scale post-combustion carbon capture and sequestration system ("CCS"), which will result in the near elimination of fPM emissions from Coal Creek Station—rendering the Final Rule unnecessarily costly and duplicative. In sum, this Final Rule, if not stayed, will have damaging and irreparable impacts on Rainbows operations, as described below.

3. This declaration is based on my personal knowledge of facts and on analyses conducted by my staff.

4. I am submitting this declaration because the Final Rule imposes immediate harm to Rainbow and its operations.

BACKGROUND ON RAINBOW'S OPERATIONS

5. Rainbow is a wholesale power generation company headquartered in Bismarck, North Dakota. Rainbow has owned and operated Coal Creek Station since May 1, 2022.

6. Coal Creek Station has been generating and distributing energy in North Dakota and the upper Midwest region of the United States since 1979. Coal Creek Station produces up to 1,151 megawatts of electricity per hour by combusting over seven million tons of beneficiated lignite (coal originally purchased from Falkirk Mining Company which then gets beneficiated in-house with a patented

pollution control technology, "DryFining™," further described below). It directly employs over 200 people at its facility near Underwood, North Dakota.

7. Since it began its commercial operation in 1979, Coal Creek Station has continuously improved its methods for controlling air pollution. Coal Creek Station stands out from other coal-fired power plants to the point that it has been acknowledged by the federal government multiple times for its environmental stewardship.[1]

8. As just one example, the Department of Energy selected Coal Creek Station to participate in a government-industry partnership, where Coal Creek Station "will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future."[2] The resultant multi-pollutant control technology, "DryFining™," improves the heating value of the coal while removing constituents that cause harmful pollution, mainly nitrogen oxide (NOx) and sulfur dioxide (SO_2). This technology is the first of its kind and remains a pioneering technology in the industry.

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[1] *See, e.g.*, 76 Fed. Reg. 58,570, 58,584 (Sept. 21, 2011) (discussing Coal Creek Station's involvement in the Clean Coal Power Initiative).

[2] National Energy Technology Laboratory, Topical Report No. 27, at 4 (June 2012) (provided as Attachment A to this Declaration).

IMPACT OF THE FINAL RULE ON RAINBOW

9. The Final Rule, under Section 112 of the Clean Air Act, revises the national emission standards for hazardous air pollutants for coal- and oil-fired electric utility system generating units. Such a category of units would include Coal Creek Station.

10. Among other changes, the Final Rule reduces the emission limit for Hg, reduces the emission limit for fPM, and requires the use of PM CEMS to demonstrate compliance with the fPM standard. Under the Final Rule, Rainbow will have to install Hg controls, and it will also have to install PM CEMS. Given its lack of experience with using PM CEMS and uncertainty as to whether it could comply with the fPM standard using this measurement system, Rainbow may also install fPM controls.

11. Because the Final Rule imposes a short compliance timeline, Rainbow cannot delay action during the pendency of litigation, and it must begin implementing the required controls and monitoring system immediately.

12. To comply with the new Hg emission limit, Rainbow will need to install new controls, specifically an activated carbon injection ("ACI") system.

13. Rainbow will need to install an ACI system, with the capital cost of the ACI system costing around $5 million.

14. Rainbow estimates the activated carbon product alone will cost approximately $145 *per hour per unit* to meet the Hg emission limit, which equates to $2.4 million per year in total for both units. This is on top of the capital expense and the operations and maintenance costs.

15. In addition, Rainbow will have to install PM CEMS to demonstrate compliance with the fPM emission limits.

16. Prior to the Final Rule, Rainbow demonstrated the emissions from both units at Coal Creek were less than half of the existing rule's limit of 0.03 lb/mmBtu and qualified the units as Low Emitting EGUs ("LEE") for fPM as defined in the rule, by demonstrating fPM emission rates of less than 0.015 lb/mmBtu over the course of 12 consecutive quarterly emissions tests. Thus, ongoing LEE qualification tests were only required every three years and have been successfully completed in 2021 and 2024. This emissions testing is completed using EPA approved methods and directly measure actual fPM in the flue gas.

17. By contrast, PM CEMS provides continuous monitoring of a parameter calculated based on a correlation developed during its certification rather than direct measurement of the fPM.

18. The results from the currently required fPM stack testing at Coal Creek Station have demonstrated that fPM emissions could reach the Final Rule's emissions limit, but it is not technologically sound to assume that Coal Creek could

maintain the emissions limit on a continuous basis with a reasonable margin of compliance. fPM emissions test results indicate variability in fPM emissions, based on numerous operational parameters which include fuel quality, load, coal drying operations and ash resistivity. The additional impact of adding ACI to the system has also not been evaluated and will result in increased fPM loading to the existing pollution control equipment.

19. By design, stack tests measure unit performance under a strict set of operating conditions—not during periods of startup, shutdown, malfunction, and the cycling driven by the high penetration of renewables within MISO. Coal Creek does not operate at a single, baseload level, or even at predictable levels, due to the amount and variability of renewable generation. Thus, testing performed under controlled conditions does not adequately reflect real world unit operation.

20. PM CEMS are a more expensive and less accurate method of measuring compliance with low emission rates. Unlike stack tests, which take a direct measurement of the flue gas to measure the actual amount of particulate matter it may contain, PM CEMS do not take direct measurements. Instead, they rely on measuring some other characteristic of the flue gas to estimate fPM based on changes in that characteristic, such as light scatter or beta attenuation. Also, the indirect nature of the PM CEMS necessitates a correlation test consisting of a minimum of 15 parallel stack test runs spanned across three different fPM levels to ensure the

readings of the CEMS are as closely correlated as possible to actual fPM emission rates measured via Method 5.[3] This recuring testing is necessary for the PM CEMS's periodic calibration and certification and will lead to increased fPM emissions to the CCS system, which will complicate CCS's removal of the fPM and result in premature fowling of the system.

21. Ultimately, the inaccuracy of the PM CEMS combined with the lower fPM emission limit presents a compound situation for Rainbow. The difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate PM CEMS, and the difficulty in using PM CEMS will be exacerbated by the dramatically lower standard. Serious concerns remain with respect to whether a PM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a PM CEMS to differentiate compliance from a false reading. Ongoing quality assurance testing is needed to ensure the PM CEMS data is valid, which in turn increases the cost of PM CEMS. Initial quotes received indicate the necessary annual audit would cost $48,000 for both units, and the three-year audit would cost $175,000 for both units.

22. Rainbow estimates PM CEMS installation on each unit at Coal Creek Station would cost $345,000-$410,000. This includes $150,000 for the analyzer, $60,000-$100,000 for stack and electrical port upgrades, $35,000 for

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[3] 40 C.F.R. Part 60 App. B, Performance Specification 11.

commissioning, and \$100,000-\$125,000 for initial certification. By contrast, because of its LEE qualification, Rainbow currently spends \$3,000-4,000 per unit annually for fPM testing.

23. Given PM CEMS's inaccuracies and uncertainties, Rainbow may be unable to meet the fPM emissions limit using PM CEMS. As a result, Rainbow may have to install fPM controls at Coal Creek Station to comply with the Final Rule's compliance deadline of July 8, 2027, three years after the effective date of July 8, 2024.

24. All these fPM-related costs and expenditures are ultimately duplicative because Rainbow is actively working to install CCS at Coal Creek Station. CCS would virtually eliminate all fPM emissions from Coal Creek Station. fPM emissions correlate directly with amine degradation. Minimizing fPM emissions into the CCS system is needed for performance of the system. Rainbow completed a FEED study for the CCS and is currently undergoing a bridge study to determine what emission controls will be installed upstream of the CCS which will further reduce fPM and decrease amine degradation.

25. Although the highly effective fPM control of CCS is recognized by EPA's own Section 111(d) Guidelines, the Final Rule does not align the timeline for installation of fPM controls with that for implementation for CCS.[4]

26. Accordingly, under the timeline for compliance with the Final Rule, Rainbow will have to begin work and thus incurring unrecoverable costs immediately.

27. Investment costs for costly and duplicative emission control methods present unique challenges to Rainbow due to its status as a "merchant power producer" in the power market. Most power in the United States is provided by either investor-owned utilities or public utilities. Both utilities operate under a vertically integrated monopoly framework. Because of their vertically integrated monopoly structure, these utilities are also heavily regulated by the government to ensure that the interests of the consumers are preserved. Such regulatory measure includes rate-setting. State regulatory commissions set the rates at a level so that the regulated utility could cover its cost of service plus a reasonable "rate of return" (profit) on the capital the utility invested on its plants, whether that be the original construction or improvements to the facility.

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[4] EPA, *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document*, at 22, 59-60, available at: https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

28. In contrast to what has been discussed above, Rainbow (through Coal Creek Station) is a privately owned "merchant power producer." Rainbow is not an investor-owned utility, nor is it a public utility. Unlike the traditional structure of many utility companies, Rainbow does not have a vertically integrated monopoly system where it controls everything from electricity generation all the way to distribution of power to the end-use consumers who, often times, could not switch electricity providers. Instead, merchant power producers would sell all the generated power into the wholesale open market.

29. Accordingly, this means Rainbow has no "captive ratepayer." While investor-owned utilities and public utilities have a set customer base (similar to how normal household consumers cannot select/switch their utility company), Rainbow has none. Rainbow does not have a monopoly over its end-use consumers; the market (and its participants) could always favor a different electricity producer if Rainbow's power production costs are too high.

30. Second, unlike investor-owned utilities and public utilities which have a chartered right—guaranteed by the state government—to recover costs (usually through rate-setting orders as discussed above), Rainbow cannot recover any capital or operational costs from its end-use customers. Rainbow has no "rate base," i.e., the right to earn a specified rate of return backed by the state energy commission, and never will as a merchant power producer.

CONCLUSION

31. For the reasons described above, Rainbow is facing imminent and substantial harm from the Final Rule.

I, Stacy L. Tschider, declare under penalty of perjury that the foregoing is true and correct.

Executed on May 12, 2024

Stacy L. Tschider
Chief Executive Officer

ATTACHMENT A

TOPICAL REPORT NUMBER 27 JUNE 2012

CLEAN COAL TECHNOLOGY

Clean Coal Power Initiative Round 1 Demonstration Projects

Applying Advanced Technologies to Lower Emissions and Improve Efficiency

A report on three projects conducted under separate cooperative agreements between the U.S. Department of Energy and:

- Great River Energy
- NeuCo. , Inc.
- WeEnergies

Cover Photos:

- Top left: Great River Energy's Coal Creek Station
- Top right: We Energy's Presque Isle Power Plant
- Bottom: Dynegy's Baldwin Energy Complex

CLEAN COAL TECHNOLOGY

Clean Coal Power Initiative Round 1 Demonstration Projects

Executive Summary

Coal is both plentiful and affordable in the United States (U.S.) and is expected to maintain its nearly 50 percent share of total electricity generation as demand increases. Our nation's energy security and environmental management depend on the resolution of environmental concerns associated with increased coal use. Cost-effective and efficient technologies developed to ensure the environmentally clean utilization of this resource have been designated as "clean coal technologies."

Clean coal technology research and development (R&D) began in the 1970s. Many promising technologies had emerged by the 1980s, but were not implemented at the commercial scale due to the financial and technical risks associated with the first commercial-scale installation. A pathway to facilitate the further development of these technologies was initiated by Congress and implemented by the U.S. Department of Energy (DOE) in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships between DOE, non-federal public entities, technology suppliers, and clean coal technology stakeholders to reduce the financial and technical risks preventing their commercial-scale implementation and demonstration.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001 to focus on enhancing the reliability of the nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002.

The CCPI is an industry/government cost-shared partnership program that furthers efficient clean coal technologies for use in new and existing U.S. electric power generating facilities. CCPI is a technology demonstration program implemented through a series of solicitations (rounds) that target priority areas of interest to meet DOE's Roadmap goals. Technologies emerging from the program will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future. CCPI is planned and managed by the DOE Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

CCPI Round 1 (CCPI-1) criteria for candidate projects was very broad in that the solicitation was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives." CCPI Round 2 (CCPI-2) encouraged proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce mercury (Hg) and other power plant emissions. CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture, recovery, and sequestration or beneficial use of carbon dioxide (CO_2) from coal-fired power plants.

Future CCPI rounds will build upon the successes of previous rounds, demonstrating advanced technologies that strengthen the nation's energy and economic security with minimal impacts to the environment and consumer.

This report describes three projects that have successfully demonstrated emissions and plant control system upgrades that support the CCPI-1 objective of ensuring that the U.S. has clean, reliable, and affordable electricity. The Baldwin Energy Complex project utilized an artificial intelligence (AI) system that increases the plant's thermal efficiency while reducing emissions. The Great River Energy (GRE) project increased boiler efficiency by reducing the fuel moisture content. The TOXECON™ project removed Hg from the flue gas stream without affecting the marketability of the fly ash.

The **Demonstration of Integrated Optimization Software at the Baldwin Energy Complex** project demonstrated the integration of advanced, on-line, combustion/emission control optimization software. The demonstration showed that an integrated process optimization approach can increase the thermal efficiency and reliability of the plant, with the concurrent benefit of a corresponding reduction of airborne emissions such as nitrogen oxides (NO_X), CO_2, and particulates.

The Cooperative Agreement for the project at the Baldwin Energy Complex was awarded on February 18, 2004. The project duration was 45 months and was completed on November 17, 2007. The project cost was $19,094,733 with a DOE share of $8,592,630 (45 percent). Project goals were met with the exception of the heat rate improvement target. However, it is believed that the heat rate goal could have been met had plant personnel not placed a higher priority on cyclone flame stability and NO_X reduction. To date, the participant has reported well over 50 sales of its optimization modules.

In GRE's **Increasing Power Plant Efficiency: Lignite Fuel Enhancement** project, waste heat from a power plant was used to lower the moisture content of the lignite fuel it consumes. Reducing the moisture content of the lignite increases the energy efficiency of the boiler, which means less fuel is required for a given load. Emissions reductions were achieved as a result of increased fuel quality, segregation of iron sulfide (pyrite) and mercury in the drying process, and increased oxidation of mercury resulting in greater mercury removal in the flue gas desulfurization (FGD) system.

A Cooperative Agreement for the Lignite Fuel Enhancement project was awarded on July 9, 2004. The project duration was 69 months with an operations completion date of March 2010. The estimated project costs were $31,512,215 with a DOE share of $13,518,737 (43 percent). The moisture content of the coal was reduced by the target amount of 8.5 percent, which resulted in a higher heating value (HHV) improvement from 6290 British thermal units/pound (Btu/lb) to 7043 Btu/lb. Also, the moisture removal process and the resulting increased fuel quality resulted in mercury (Hg) emissions being reduced by 41 percent, with NO_X and sulfur dioxide (SO_2) reduced by 32 and 54 percent, respectively. GRE has reported that 120 organizations have signed the necessary secrecy agreements to obtain detailed information on the technology. Some studies have been carried out to evaluate the technology for specific applications.

The **TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers** project (TOXECON™) was an integrated Hg, particulate matter, SO_2, and NO_X emissions control demonstration program for application on coal-fired power generation systems. The TOXECON™ process utilized sorbents that were injected into a pulse-jet baghouse to control emissions. The technology was configured to not affect fly ash quality and its potential to be sold for constructive use. **TOXECON™** has been installed at seven plants in addition to Presque Isle Power Plant (PIPP) and robust sales of the Hg Continuous Emissions Monitor (CEM) have been reported. The recently released new Hg standard is expected to provide additional impetus for future application.

The total project cost was $47,512,830, with DOE providing $23,756,415 (50 percent). The demonstration began operation in January 2006, and was completed in September 2009. The project achieved the emissions reduction goals of 90 percent for Hg and 70 percent for SO_2 individually; however, the concurrent reduction of these emissions through an integrated treatment process was not consistently achieved. All remaining project goals, except for NO_X reduction, were met.

Clean Coal Technology Demonstration Program (CCTDP)

According to the Energy Information Administration's Annual Energy Outlook 2011, the demand for electricity in the United States is projected to increase by 25 percent by the year 2035. Because coal is both plentiful and affordable, the generation of electricity from this abundant resource is expected to continue to account for nearly 50 percent share of total generation. The nation's energy and economic security and environmental quality depend on the resolution of environmental concerns associated with increased coal use. These concerns can be addressed through the development of technology-based solutions that ensure environmentally clean energy utilization. These solutions must be both cost-effective and efficient to support economic growth. This new generation of technologies has been designated as "clean coal technologies."

The R&D of clean coal technologies began in the 1970s, with many promising technologies having emerged by the 1980s. The technologies were, however, unproven in a commercial setting and not implemented due to financial and technical risks. A pathway was needed to prove their technical performance and cost competitiveness in a commercial setting in order to facilitate their acceptance and reduce the risk of implementation. This pathway was initiated by Congress and implemented by the DOE beginning in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships among the DOE, non-federal public entities, technology suppliers, and other clean coal technology stakeholders to reduce the financial and technical risks preventing the demonstration and commercialization of these technologies. As a condition of participation, CCTDP demonstrations were required to be at a scale and in an operational environment sufficient to determine their potential for satisfying marketplace technical, economic, and environmental needs.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001, which called for technologies that could be rapidly implemented to enhance the reliability of the

THE CLEAN COAL TECHNOLOGY PROGRAM

The DOE commitment to clean coal technology development has progressed through three phases. The first phase was the Clean Coal Technology Demonstration Program (CCTDP), a model of government and industry cooperation that advanced the DOE mission to foster a secure and reliable energy system. With 33 projects completed, the CCTDP has yielded technologies that provide a foundation for meeting future energy demands that utilize the vast U.S. reserves of coal in an environmentally sound manner. Begun in 1985, the CCTDP represents a total investment value of over $3.25 billion. The DOE share of the total cost is about $1.30 billion, or approximately 40 percent. The project industrial participants (non-DOE) have provided the remainder, nearly $2 billion.

Two programs have built on the successes of the CCTDP. The first is the Power Plant Improvement Initiative (PPII), a cost-shared program patterned after the CCTDP and directed toward improved reliability and environmental performance of the nation's coal-burning power plants. Authorized by the U.S. Congress in 2001, the PPII concluded with four successfully completed projects that focused on technologies enabling coal-fired power plants to meet increasingly stringent environmental regulations at the lowest possible cost. The total value of these projects is $71 million, with DOE contributing $31 million or 42.7 percent.

The second follow-on program is the Clean Coal Power Initiative (CCPI). Authorized in 2002, the CCPI had a goal of accelerating commercial deployment of advanced technologies to ensure that the nation has clean, reliable, and affordable electricity. The first CCPI solicitation (CCPI-1) was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives." Of five projects awarded, two were discontinued and three were successfully completed. The total cost of the five projects was approximately $121 million, with the DOE share being $54 million or 44.8 percent. In February 2004, the second CCPI solicitation (CCPI-2) was issued seeking proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advances that reduce mercury and other power plant emissions. In October 2004, four projects were selected. One project withdrew prior to award, one is complete, and two are ongoing. The three awarded projects are valued at over $4 billion with a DOE share of $322 million. On August 11, 2008, DOE issued the Funding Opportunity Announcement for the third solicitation (CCPI-3A). CCPI-3A specifically focused on the capture and sequestration, or beneficial reuse, of CO_2 emissions from coal-based electricity production (minimum 50 percent gross energy output as electricity). Following the passage of ARRA, DOE announced the re-opening of the third solicitation. On June 9, 2009, DOE issued an amendment that provided for a second application due date (CCPI-3B) of August 24, 2009. A total of $1.4 billion was made available for awards under CCPI-3A and -3B. Of the total amount, approximately $800 million was provided under ARRA with the remainder provided through the annual congressional appropriations process. Of the four projects awarded, one withdrew and three are ongoing. The three ongoing projects are valued at over $6 billion with a DOE share of approximately $1 billion.

nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002. CCPI ensures the ongoing development of advanced systems for commercial power production emerging from DOE's core fossil-fuel research programs.

CCPI Program

As coal is likely to remain one of the nation's—and world's—lowest-cost electric power resources for the foreseeable future, a new commitment to further reduce the environmental challenges of its continued use through even more advanced clean coal technologies is required. CCPI is an innovative technology demonstration program initiated to foster more efficient, advanced, clean coal technologies in the 21st century for use in new and existing electric power generating facilities in the U.S. CCPI solicitations began in 2002. As of this report, three solicitations have been issued (CCPI-1, CCPI-2, and CCPI-3). After the submission of proposals for the initial CCPI-3 solicitation (CCPI-3A), the solicitation was re-opened with minor amendments for a second round of proposals (CCPI-3B). Projects selected under CCPI-3A and -3B could be funded, in whole or in part, from funds appropriated under the American Recovery and Reinvestment Act of 2009 (ARRA).

CCPI builds on the successes of the original CCTDP and encompasses a broad spectrum of research and large-scale projects that target today's most pressing environmental challenges. CCPI is an industry/government cost-shared partnership that accelerates commercial deployment of advanced technologies to ensure a reliable and affordable supply of electricity while simultaneously protecting the environment. CCPI is planned and managed by DOE's Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

The CCPI mission is to enable and accelerate deployment of advanced technologies to ensure that the United States has clean, reliable, and affordable electricity. This mission is executed through the CCPI program goals of reinvigorating private sector development of new coal-based power technologies that can meet increasingly stringent environmental regulations, and establishing the technological foundation for "zero" emission coal-based energy facilities within the nation's power industry.

REGULATORY HISTORY

Title III of the 1990 Clean Air Act Amendments (CAAA) identified 189 substances emitted by fossil fuel combustion that may be toxic or hazardous. These 189 substances are usually referred to as hazardous air pollutants (HAPs) or air toxics. The CAAA required the Environmental Protection Agency (EPA) to evaluate these pollutants by source as well as their potential harm to human health and the environment. The EPA was also required to determine the need to control the emission of HAPs. DOE's NETL, in collaboration with the Electric Power Research Institute (EPRI), comprehensively addressed the CAAA requirements specific to the electric power industry with a series of projects from 1990 to 1997. In the course of these projects, it was found that non-mercury toxic metals were captured by existing particulate removal equipment and that they were emitted at or near their detection limit. These projects provided the majority of the data for two Congressionally-mandated EPA Reports to Congress. The first report, the "Mercury Study Report to Congress," was issued in 1997 and found that coal-fired power plants were the largest U.S. source of anthropogenic mercury emissions. The second report, the "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units–Final Report to Congress" was issued in 1998. This second report concluded that mercury from coal-fired power plants was the HAP of "greatest potential concern." This conclusion lead to the initial emphasis on regulating mercury and the development of mercury capture technologies and that additional research and monitoring was warranted for the other HAPs.

In 1999 and 2000, the EPA, in cooperation with DOE, issued an Information Collection Request (ICR). The purpose of the ICR was two-fold. One aim was to refine the mercury emission inventory from coal-fired power plants. The other was to determine the mercury control capabilities of existing and new, potentially viable technologies. In the same timeframe, the National Academy of Sciences (NAS) conducted an evaluation of the health impacts of mercury. Based on the ICR and the NAS evaluation, the EPA determined that there was a "plausible link" between emissions of mercury from coal-fired power plants and the bioaccumulation of mercury in fish, as well as animals that eat fish. Since consumption of fish is the primary pathway for human exposure to mercury, the EPA determined that it was necessary to reduce mercury emissions from fossil fuel combustion in power plants. The EPA issued its decision to regulate mercury in December of 2000.

The EPA issued the Clean Air Mercury Rule (CAMR) on March 15, 2005. This was the first regulation to specifically address mercury emissions from coal-fired power plants. The CAMR complemented the Clean Air Interstate Rule (CAIR), which was issued to reduce the emissions of NO_X and SO_2, since technologies designed to remove other pollutants often coincidentally remove some mercury. The net effect of these two rules was expected to be a 70 percent reduction in mercury emissions, which are currently estimated at 48 tons per year. The CAMR intended to create a market-based cap-and-trade program to reduce mercury emissions. The reduction would have taken place in two phases. Mercury emissions were to be capped at 38 tons per year in 2010. This level of emissions would have been achieved by coincidental mercury capture in technologies whose primary purpose is the control of other pollutants. By 2018, total mercury emissions from all coal-fired power plants were to be limited to 15 tons per year. In addition, new coal-fired units would have to meet New Source Performance Standards.

The CAMR was applicable to all coal-fired utility boilers with a heat input of 73 MW (thermal) or 250 million Btu per hour. Industrial cogeneration boilers would have been regulated if they sell over 25 MW of electrical power and more than one third of their maximum output to a power distribution system. In 2008, the D.C. Circuit Court vacated the CAMR and remanded the CAIR. The EPA Administrator signed a new rule on December 16, 2011, and it was published in the Federal Register on February 16, 2012. This rule, Mercury and Air Toxics Standards (MATS), regulates mercury, HCl, and a number of non-mercury air toxic metals emitted from power plants. These are antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se). MATS include separate standards for existing plants and new or refurbished generating units. Each unit is also regulated differently depending on whether it burns low rank or non-low rank coal. All power plants have three years to comply and the deadline can be extended one year by state agencies—an option expected to be broadly available.

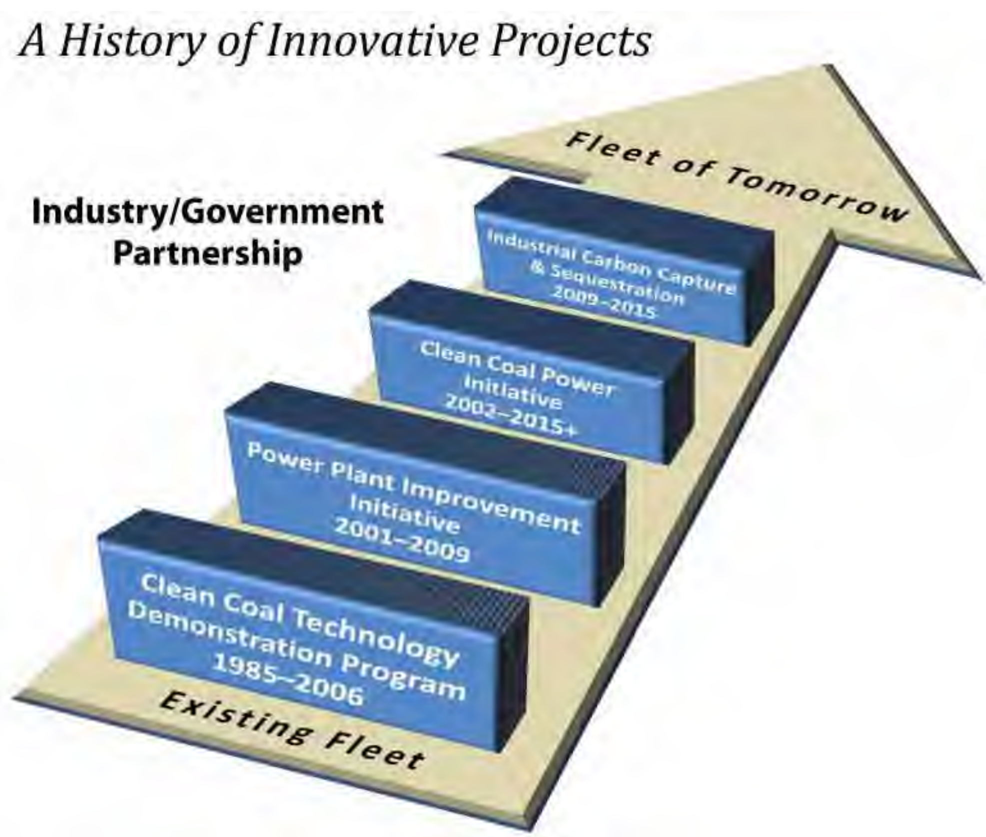
MATS establishes alternative quantitative emission standards, including SO_2 (as a surrogate for HCl). Filterable particulate matter serves as a surrogate for non-mercury air toxic metals, which can also meet a standard based on the total emissions of the eight non-mercury air toxic metals or the plant may meet a separate standard for each of these metals. The standards set work practices instead of numerical limits to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal- and oil-fired power plants. In MATS the emission standards for new or refurbished plants are expressed as pounds per megawatt hours or pounds per gigawatt hours. Existing plants can meet standards based on either electric power output or the heat content of the coal fed to the boiler.

According to “Clean Coal Technology Programs: Program update 2006”, CCPI Round 1 (CCPI-1) criteria for candidate projects was very broad in that the solicitation was open to “any technology advancement related to coal-based power generation that results in efficiency, environmental and economic improvement compared to currently available state-of-the-art alternatives.” The broad approach taken by CCPI-1 was intended to benefit from the full range of technological advancements made since the last major clean coal technology solicitation had been issued in 1992. Of the eight projects initially selected under CCPI-1, five awards were made. Two of the awarded projects ended prior to successful completion. The remaining three projects are complete and are the subject of this report.

CCPI-2 encouraged proposals that demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce Hg and other power plant emissions. The choice of the CCPI-2 solicitation categories reflected DOE’s judgment of the most pressing technological needs confronting the nation’s power industry in the 2010 to 2020 time frame.

CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture and sequestration or the beneficial use of carbon dioxide (CO_2) from coal-fired power plants. The technologies to be demonstrated could consist of new, integrated facilities or retrofits of existing plants. After an initial round of projects was awarded, a second round of projects was awarded under CCPI-3 in December 2009 with funds made available under ARRA.

The CCPI is closely linked with R&D activities paving the way for ultra-clean, fossil-fuel based energy complexes in the 21st century. The Clean Coal Technology Roadmap was developed in January 2004 with the cooperation of the coal and power industry to address short- and long-term coal technology needs, which support the clean coal initiatives. Projects selected under the CCPI advance efficiency, environmental performance, and cost competitiveness well beyond that of technologies that are currently in commercial service, which is consistent with the Energy Policy Act of 2005.



DOE’s Coal Demonstration Programs

Demonstration of Integrated Optimization Software at the Baldwin Energy Complex

Introduction

A coal-fired power plant is a complex grouping of dynamic and interrelated systems. An effort to optimize one aspect of the operation of a system has the potential, in some cases, to adversely affect other operational aspects of the same or different systems. An example would be that reducing the heat rate of a power plant through an increase in combustion efficiency might also result in an increase in the rate of NO_x formation due to possible higher combustion temperatures. Therefore, overall plant optimization must include the ability to monitor individual systems and ensure their operation is not adversely impacted by changes in the same or related systems.

NeuCo, Inc. (NeuCo) of Boston, Massachusetts, demonstrated overall plant performance optimization by utilizing sophisticated computational techniques to increase power plant efficiency and reduce air emissions at the Dynegy Midwest Generation Baldwin Energy Complex (BEC). The BEC consists of three 600 megawatt electric (MWe) coal-fired units located in Randolph County, Illinois, which are designed to fire high-sulfur bituminous coal. All three units switched to Powder River Basin (PRB) coal in 2002 to reduce SO_2 emissions.

The Cooperative Agreement was awarded on February 18, 2004, and the project was completed on November 17, 2007. The project cost was $19,094,733 with a DOE share of $8,592,630 (45 percent).

Project Objectives

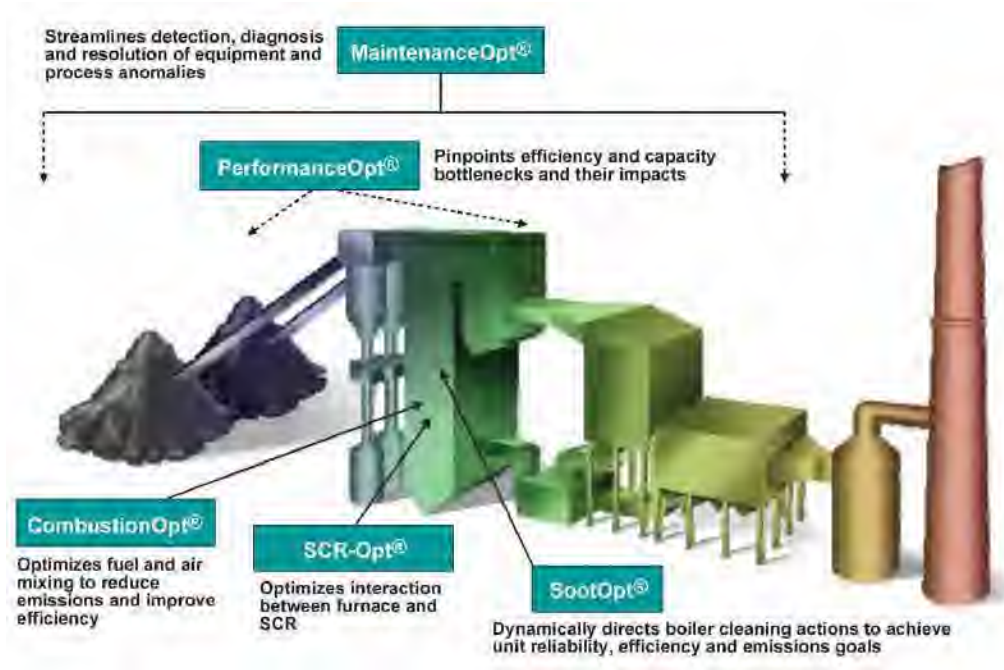
Project objectives were to reduce the BEC NO_x emissions by five percent, increase efficiency by 1.5 percent, and increase net annual electrical power production by 1.5 percent by improving reliability and availability. Additional objectives were to reduce greenhouse gases, Hg, and particulates, and to increase profitability through lower costs, improved reliability, and greater commercial availability. The overarching objective for the application of integrated optimization software to coal-fired power plant operations was to improve coal-based generation's emission profile, efficiency, maintenance requirements, and plant asset life such that the abundant coal resources of the United States remain viable well into the foreseeable future.

The need for integrated optimization software arose, in part, due to the dynamic complexity of the systems present in both modern and retrofitted coal-fired power plants. The optimization process differs significantly from that of normal power plant system operation. Typically, operators make occasional adjustments to the various controls to maintain a process output within an acceptable range based on their understanding of how the adjustment will affect unit performance. While this method keeps operating parameters within an acceptable range, it does not optimize unit operation. However, a control system with optimization capability can explore the relationships between the variables in a system and manage performance more dynamically. An integrated optimization system adds another level of control at the combined system level to optimize not only each system, but the overall performance of all managed systems as well. With the objective of integrated optimization in mind, five separate but integrated optimization modules were developed that addressed the following plant systems: combustion, sootblowing, selective catalytic reduction (SCR) operations, overall unit thermal performance, and plant-wide availability optimization.

Project Description

The NeuCo project at BEC consisted of the design, installation, and demonstration of five integrated AI-based optimization modules for coal-fired power plant operations. Performance optimization modules were developed and implemented for three plant systems: combustion, sootblowing, and SCR operations. In addition, supervisory modules were demonstrated for overall unit thermal performance and plant-wide maintenance optimization. The five individual optimization modules were linked together and coordinated by NeuCo's proprietary ProcessLink® technology.

These optimization modules, although separate, communicated through NeuCo's ProcessLink technology. The modules on Units 1, 2, and 3 did not use theoretical or empirical relationships to model respective unit operations, but rather the technology "learned" these relationships from actual unit operations. The learning capability of the technology was based on the use of neural networks (NNs), first principles, expert systems,



Overview of the Optimizers at BEC

direct search optimization, and fuzzy logic (FL) in addition to enterprise software and a robust calculation engine to link the individual optimization modules and achieve the optimum overall result.

The demonstration technology operated in two modes: closed loop and an advisory mode. The closed loop mode permitted the optimization modules to directly control the plant in real-time. The advisory mode provided guidance to the operator, who then decided whether or not to implement the technology.

CombustionOpt and SCR-Opt

CombustionOpt and SCR-Opt were tightly integrated and are described together. CombustionOpt and SCR-Opt used neural network technology to learn relationships among system variables without the need for prior understanding of what those relationships might be. Once the relationships were learned, CombustionOpt used this Information to change input variables to achieve the performance objectives determined by the plant operators. The learning process was ongoing and based on real-time and recent data so as to constantly update the relationship between system input variables and the desired performance objectives. Important system variable relationships for the CombustionOpt module included plant heat rate, the rate of NO_X formation in the furnace, and ammonia (NH_3) consumption for the SCR system installed on Units 1 and 2.

CombustionOpt calculated the control settings that improved the mixing of the fuel and air in the furnace in real-time for literally dozens of different dampers and actuators, leading to reduced furnace NO_X production while maintaining combustion efficiency. Additionally, the calculations were repeated every minute resulting in more numerous, but smaller changes based on current boiler conditions. Not only were process outputs kept within an acceptable range of operation, they were optimized within that range to meet performance objectives established by plant operators.

If a unit is equipped with an SCR, CombustionOpt and SCR-Opt are integrated to mix the fuel and air in the furnace to reduce furnace NO_X production and maintain critical combustion parameters such as combustion efficiency, while increasing SCR efficiency. The integrated goals of these models are to maintain Cyclone Main Flame Scanner Quality and reduce SCR inlet NO_X, which results in lower NH_3 flow to the SCR system. Therefore, by using an integrated control approach, both furnace and SCR performance are optimized.

SootOpt

A sootblowing operation utilizes steam (or other media) for cleaning the boiler tubes. It does so at the expense of unit efficiency because energy is required to generate the cleaning media. Sootblowing also results in wear on the boiler parts being cleaned. However, slagging and fouling can also result in lower furnace efficiency, increased NO_x production, and excessive flue gas exit temperatures. SootOpt optimized cleaning action effectiveness and achieved improved boiler performance by minimizing the energy expended to generate cleaning media.

SootOpt combined sophisticated optimization methods in conjunction with a control system to optimize the power plant boiler soot blowing operation. SootOpt replaced the traditional schedule-based and operator-controlled soot blowing philosophy, which was basically a disadvantageous hit-or-miss approach.

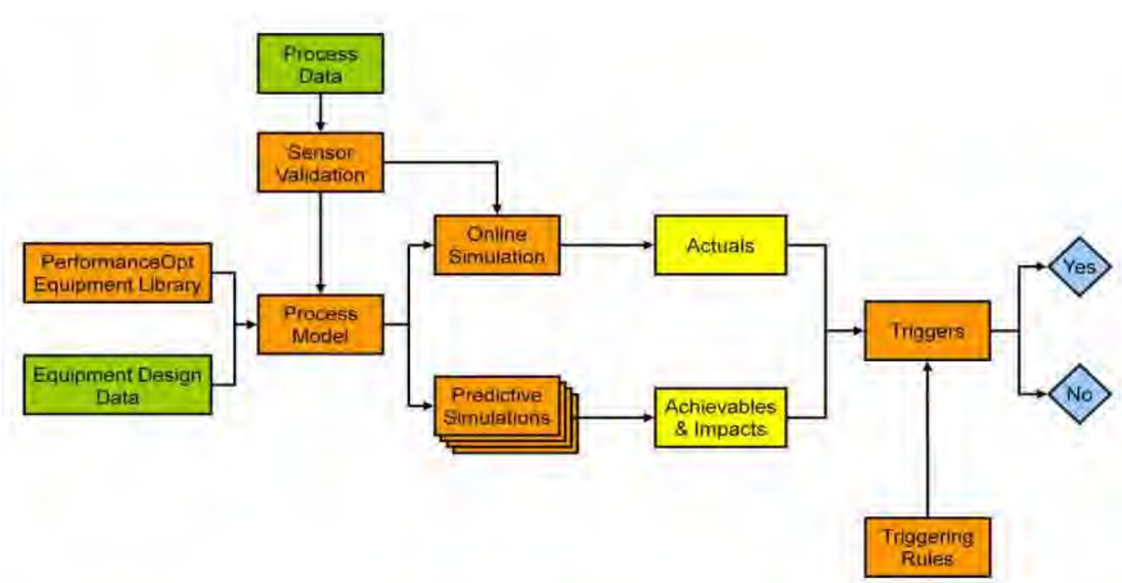
PerformanceOpt

PerformanceOpt provided a predictive performance management capability that identified efficiency and capacity losses so that operators could lower operating costs by remedying their cause. PerformanceOpt identified problems that were causing plant performance limitations by comparing actual plant performance to predicted performance. The predictive component of PerformanceOpt performed mass and energy balances on a minute-by-minute basis and computed the results for thousands of variables by utilizing a detailed first-principles model of the unit with scenario generation capability to quantify what was achievable under current operating conditions. PerformanceOpt continuously monitored key equipment and unit-level performance factors and detected, in real-time, when actual performance deviated from what had been predicted. For each problem identified, PerformanceOpt calculated the efficiency and capacity benefit that could be realized by resolving that problem. PerformanceOpt also ensured model accuracy and reliability through sensor validation mechanisms and equipment out-of-service logic.

MaintenanceOpt

MaintenanceOpt continuously monitored process and equipment data to identify anomalies that might indicate reliability, capacity, or efficiency problems. In addition to potential problem detection, MaintenanceOpt added value by suggesting the most likely causes of problems and estimating the impacts on efficiency, reliability, and capacity. These estimates formed a basis for MaintenanceOpt to prioritize the order in which to address the problems.

MaintenanceOpt provided plant engineers with a suite of diagnostic tools that assisted them with the process of problem correction and increased its effectiveness. Among the knowledge tools available were diagnostics, recommended actions, and the identification of potential



PerformanceOpt Components in Problem Identification

impacts and risks. MaintenanceOpt demonstrated the capability to detect both slowly developing problems as well as those that could have a critical near-term reliability impact. Sufficient information was available within MaintenanceOpt to assist plant engineers in determining the legitimacy of the problem—whether it is real or the result of a sensor malfunction. And finally, MaintenanceOpt supported the diagnosis and resolution of problems found by other optimizers such as PerformanceOpt, CombustionOpt, and SootOpt.

Results

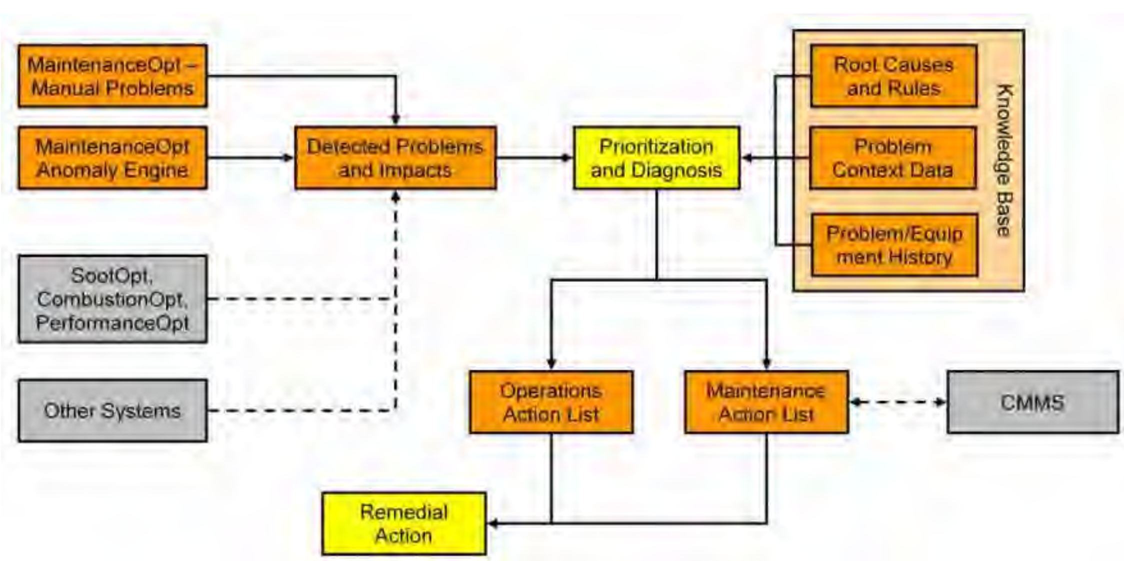
The optimizer modules were developed and refined during the project period. The optimization modules, in concert with NeuCo's proprietary ProcessLink® technology, directly controlled the plant in closed loop mode or advised plant operators of suggested actions in an advisory mode. The results discussed in this section were obtained with the technology operating in the closed loop mode.

Different combinations of the optimization modules were installed on each of the three BEC units. Unit 1, which is a cyclone-fired unit, was equipped with the CombustionOpt, SCR-Opt, PerformanceOpt, and MaintenanceOpt modules. Unit 2, which is also a cyclone-fired unit, was equipped with the CombustionOpt, SCR-Opt, SootOpt, PerformanceOpt, and MaintenanceOpt modules. Unit 3, a tangentially-fired unit, was equipped with CombustionOpt, SootOpt, and MaintenanceOpt modules.

The reported average NO_x emission reduction of between 12 and 14 percent exceeded the original goal of five percent. This significant reduction in NO_x emissions was attributed to a priority trade-off made by plant personnel that is discussed in detail later in this section. The modules attributed to the NO_x reduction actions were CombustionOpt, SootOpt, and SCR-Opt. An additional benefit was a drop in NH_3 consumption in the selective catalytic reduction (SCR) system.

NeuCo reported that the goal of increasing available megawatt hours (MWhs) by 1.5 percent was met through the information provided by the optimization modules for plant personnel use and by improved process management. The switch from high-sulfur, high-Btu Illinois coal to PRB coal had the potential to lower plant performance because of plant design and operating experience issues. With the optimization modules providing prioritized alerts and knowledge-based diagnostics for a wide array of plant equipment and process anomalies, it is reasonable to assume that the plant was able to avoid some of the unit output derating it might have encountered otherwise. Additionally, the demonstration technology also improved the management of cyclone flame quality through heightened monitoring of cyclone conditions, which likely avoided some degree of unit output derating resulting from cyclone slag build-up.

The goal of demonstrating commensurate reductions in greenhouse gases, mercury (Hg), SO_2, and particulates was achieved because of the improved heat rate brought about by reduced coal consumption.



MaintenanceOpt Workflow for Problem Detection, Diagnosis, and Resolution

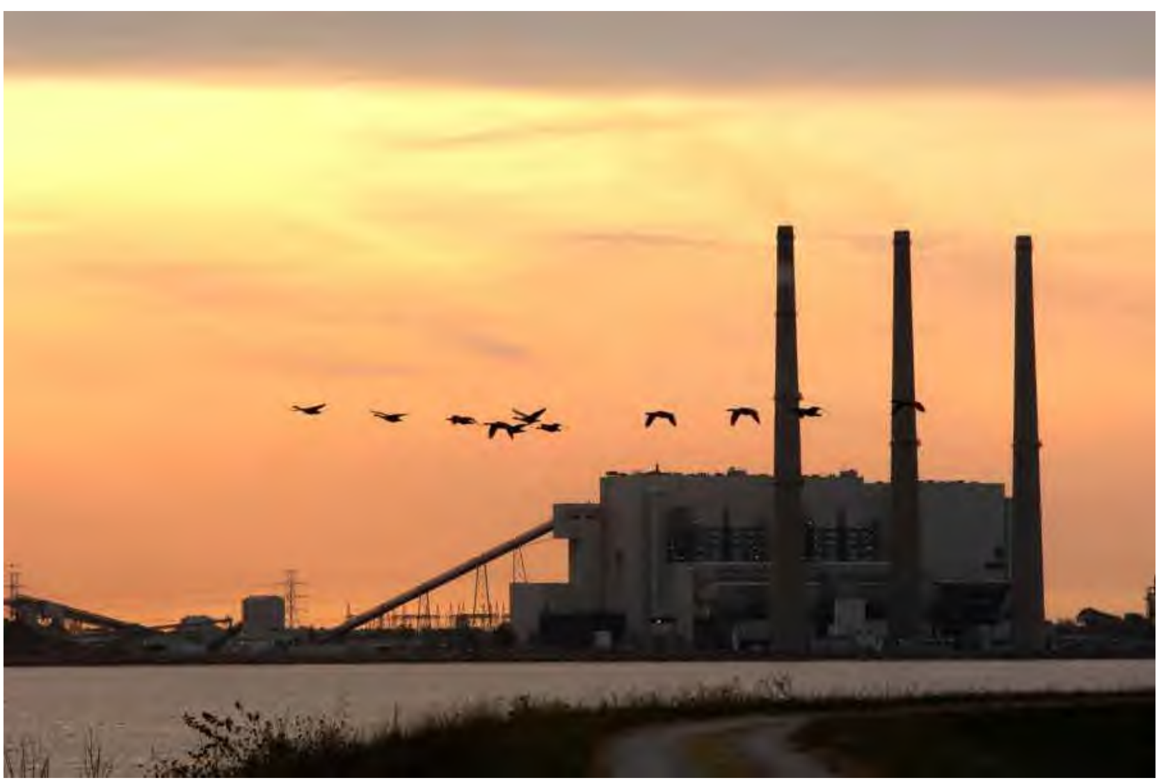
The goal of achieving commensurate increases in profitability resulting from lower costs, improved reliability, and greater commercial availability was achieved as the direct result of the full or partial completion of all other goals. Improvement in plant heat rate resulted in less coal consumption, which ultimately led to reduced costs at constant net output. Also, reducing plant generation derates as a result of both improved operating knowledge and equipment/process management resulted in enhanced plant reliability and availability.

The application of the various performance optimization modules resulted in an overall improvement in plant heat rate of 0.7 percent. The 0.7 percent improvement was roughly half the target because competing priorities prevented full achievement of the goal. The two competing priorities were set by plant personnel. The first was to place a high priority on furnace cyclone stability/availability, as the cyclones were designed to operate with bituminous coal instead of the PRB currently used. The second was to place a higher priority on minimizing NO_x production. Given the flexibility of the modules to exceed the NO_x reduction goal, it is likely that the 1.5 percent heat rate improvement goal would have been achieved had NO_x reduction not been given a higher priority. An additional factor that may have contributed to the lower improvement in heat rate was the deteriorating fuel quality received by the BEC that may have resulted in an actual increase of the baseline heat rate had the optimization packages not been used.

Benefits

The NeuCo project demonstrated an artificial intelligence (AI)-based optimization technology that can be applied to many existing coal-fired power plant boilers as well as boilers fired by other fossil fuels. The modular optimization technology was integrated with plant instrumentation and controls and provided a flexible suite of controls and diagnostic functionality that enhanced plant operations, reduced emissions, and rendered maintenance activity more effective.

The technology demonstrated the ability to respond the priority placed on NO_x reduction by plant personnel by exceeding the NO_x reduction goal while still improving, but not meeting, the heat rate goal. It is believed that, had the objectives been prioritized differently, the project would have achieved the target NO_x reduction and heat rate improvement goals.



Baldwin Energy Complex

ARTIFICIAL INTELLIGENCE

Artificial intelligence (AI) is commonly defined as the science and engineering of making intelligent machines, especially intelligent computer programs. Relative to applications with coal-fired power plants, AI consists of aspects or considerations that deal with the following:

- Neural networks, which mimic the capacity of the human brain to handle complex nonlinear relationships and "learn" new relationships in the plant environment.
- Advanced algorithms or expert systems that follow a set of pre-established rules written in code or computer language.
- Fuzzy logic (FL), which involves evaluation of process variables in accordance with approximate relationships that have been determined to be sufficiently accurate to meet the needs of plant control systems.

Neural networks (NNs) are a class of algorithms that simulate the operation of biological neurons. The NN learns the relationships among operating conditions, emissions, and performance parameters by processing the test data. In the training process, the NN develops a complex nonlinear function that maps the system inputs to the corresponding outputs. This function is passed on to a mathematical minimization algorithm that finds optimum operating conditions.

Neural networks are composed of a large number of highly interconnected processing elements that work in parallel to solve a specific problem. These networks, with their extensive ability to derive meaning from complicated or imprecise data, can be used to extract patterns and detect trends that are too complex to be detected by either humans or other computer techniques. Neural networks are trainable systems that can "learn" to solve complex problems and generalize the acquired knowledge to solve unforeseen problems. A trained NN can be thought of as an expert in the category of information it has been given to analyze. Neural networks are considered by some to be best suited as advisors, i.e., advanced systems that make recommendations based on various types of data input. These recommendations, which will change as power plant operations change, suggest ways in which plant equipment or technologies can be optimized.

Advanced algorithms, on the other hand, are programmed to incorporate established relationships between input and output information based on detailed knowledge of a specific process. They are used by computers to process complex information or data using a step-by-step, problem-solving procedure. In particular, genetic algorithms provide a search technique to find true or approximate solutions to optimization problems. These algorithms must be rigorously defined for any computational process since an established procedure is required for solving a problem in a finite number of steps. Algorithms must tell the computer what specific steps to perform and in what specific order so that a specified task can be accomplished. Advanced algorithms are now part of the sophisticated computational techniques being successfully applied to power plants to increase plant efficiency and reduce unwanted emissions.

Fuzzy logic (FL), the least specific type of AI software, is equipped with a set of approximate rules used whenever "close enough is good enough." Fuzzy logic is a problem-solving control-system methodology that has been used successfully with large, networked, multi-channel computers or workstation-based data-acquisition and control systems. Fuzzy logic can be implemented via hardware, software, or a combination of both. Elevators and camera auto-focusing systems are primary examples of FL systems. Fuzzy logic stops an elevator at a floor when it is within a certain range, not at a specific point.

Fuzzy logic has proven to be an excellent choice for many control system applications since it mimics human control logic. By using an imprecise but very descriptive language, FL deals with input data much like a human operator. Fuzzy logic is very robust and provides a simple way to arrive at a definite conclusion based upon vague, ambiguous, imprecise, or missing input information. However, while the FL approach to solving control problems mimics human decision-making, FL is much faster. The FL model is empirically based, relying on operator experience rather than technical understanding of the system.

While the heat rate improvement goal was not met, a significant improvement was demonstrated, resulting in a potential fuel cost savings benefit. Further potential savings would be achieved by utilizing the system equipment performance diagnostic capabilities.

The demonstration of NeuCo optimization technology at the BEC resulted in improved reliability, higher output, and lower maintenance costs, but these benefits were difficult to quantify precisely. Environmental conditions and coal properties changes, as well as equipment wear and many other factors, could have obscured some portion of the optimization systems' benefits.

Improved reliability, reduced maintenance costs, and higher efficiency will not only benefit the power plant, but reduce consumer costs while the improved environmental performance contributes to a cleaner environment. The participant validated the technical and cost benefits described above by the sale of 57 optimization packages through December 31, 2011. These sales were all for application on coal-fired units. Although there is no available sales data, the participant has indicated that some of the optimization packages are capable of comparable or better improvements on other fossil fueled generating units.

Conclusions

The five plant optimization products developed and demonstrated during the course of the project have the potential to provide operational, economic, and environmental benefits for many types of power plant boilers. These systems operate with existing control equipment and sensors thus minimizing system installation cost. In addition, installation does not require substantial plant downtime.

NeuCo indicated that the payback period for the demonstration technology is well under a year for a typical U.S. fossil-fired plant. The actual benefits realized and payback period required may vary depending on the circumstances at specific power plants. The performance benefits, low cost, and inherent flexibility of the technology have generated significant interest within the fossil fuel-fired electrical generation industry.

Increasing Power Plant Efficiency: Lignite Fuel Enhancement

Introduction

U.S. lignite coals have a moisture content ranging from 25 to 40 percent, and can require approximately seven percent of the fuel heat input in the furnace to evaporate it. This level of moisture places additional requirements on power plants to compensate for higher fuel flow rates and the subsequent upstream and downstream effects (such as higher processing power requirements, higher maintenance, and lower plant efficiency) when compared to the use of eastern bituminous coals. Despite their high moisture content, western lignite coals, as well as subbituminous coals, are attractive due to their low cost, lower emissions when combusted, and high reactivity.

Coal dewatering and drying processes developed thus far are complex, expensive, and require high-grade heat to remove moisture. Consequently, these processes have not gained industry acceptance. A promising low-temperature coal drying process has been developed by Great River Energy (GRE) that utilizes plant waste heat to reduce the lignite moisture content in a fluidized bed dryer (FBD) at GRE's Coal Creek Station (CCS) in Underwood, North Dakota.

The National Environmental Policy Act (NEPA) requirement for the GRE project was met with an Environmental Assessment and issuance of a Finding of No Significant Impact (FONSI) on January 16, 2004. A Cooperative Agreement was awarded on July 9, 2004. The commercial demonstration completed operations in March 2010. The estimated project costs are $31,512,215. The DOE share is $13,518,737 (43 percent) and the GRE share is $17,993,478 (57 percent).

Coal Creek Station

Project Objectives

The overarching objective of GRE's project was to increase the value of lignite as a fuel by reducing its moisture content using an innovative coal dryer concept that conserved low grade heat from the power plant that would otherwise be discharged to the environment. The Lignite Fuel Enhancement project supported this objective through the demonstration of a 5 to 15 percentage point reduction in lignite moisture content (a moisture content reduction from approximately 40 to 30 percent, which is about 25 percent of the total moisture content) at GRE's CCS.

The project demonstration was conducted in two phases. During Phase 1, a coal dryer prototype was designed and installed at CCS Unit 2 and a testing program was initiated. The objectives of prototype testing were to acquire operating experience with the dryer, confirm pilot results, and quantify the effect of dryer operational parameters so that optimal performance would be achieved. An additional objective was to incorporate the lessons learned during prototype testing into the design of the dryers being installed during Phase 2 of the project. The prototype was operated from 2006 to 2009 to obtain data for the design of full-size dryers.

The Phase 2 project objectives were to design, build, and install a full-scale coal drying system on the nominal 546 MW Unit 2, and to conduct a full-scale, long-term, operational moisture reduction test. The moisture reduction testing included determining the magnitude of Unit 2 efficiency improvement, quantifying the emissions reduction, and assessing the effects of burning dried coal on unit operation.

Project Description

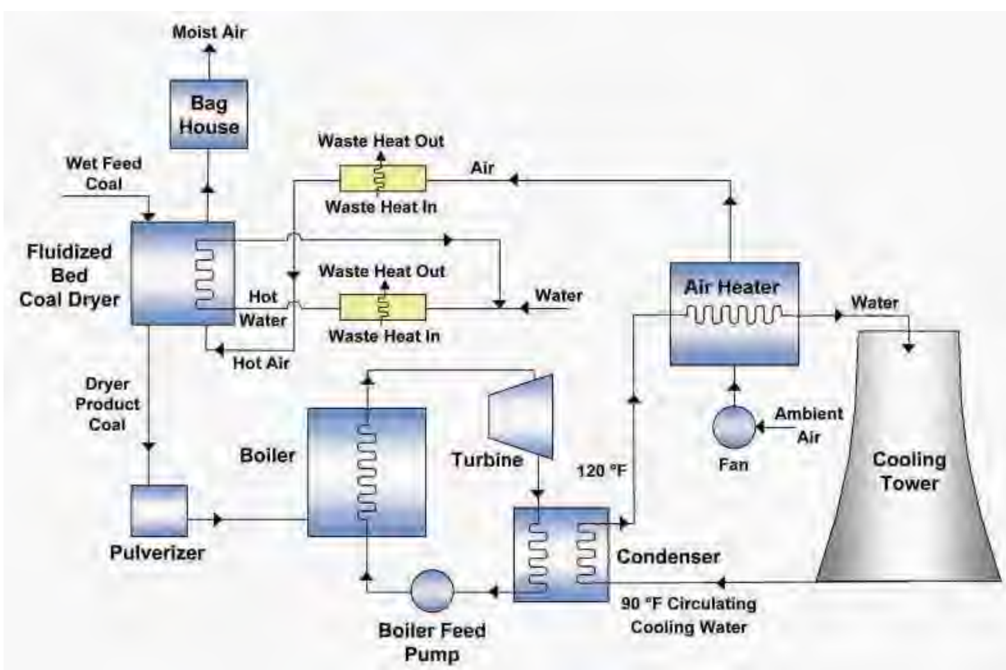
This project has its roots in lignite drying technology R&D conducted by GRE and others since the 1990s. As the R&D work progressed, GRE became convinced of the viability of the lignite drying concept. After identifying a fluidized-bed coal dryer (FBCD) in 2002 as their coal drying technology of choice, GRE submitted an application to DOE under CCPI-1 to continue development of the technology with the commercial demonstration of a prototype FBCD, and, using the lessons learned from the prototype, to develop and install a full-size coal drying system on one unit at CCS. A Cooperative Agreement was negotiated with DOE for funding under CCPI-1 in July 2004.

CCS is a two unit, lignite-fired power plant that supplies electricity to 38 member cooperatives in Minnesota. The plant consists of two identical tangentially fired Combustion Engineering (CE) boilers, each supplying a single steam turbine. Both units are nominally rated at 546 MW. The station burns approximately seven million tons of lignite per year. The design steam conditions are 1,005 degrees Fahrenheit (°F) for main and reheat steam temperature at 2,520 pounds per square inch-absolute (psia) throttle pressure. The CCS has eight pulverizers per unit (seven active and one spare). The station has two single-reheat General Electric G-2 turbines. The plant rejects heat to the environment through three mechanical draft cooling towers. Lignite, with an HHV of 6,200 Btu/lb and total moisture content of approximately 38 percent, is supplied from the nearby Falkirk mine.

In the lignite drying process cooling water leaves the condenser carrying the waste heat rejected by the steam turbine. Before the water reaches the cooling tower, where its heat would normally be discharged to the environment, it first passes through an air heater. In the air heater, a fan-driven air stream picks up some of the waste heat from the cooling water. The heated air is then sent to the FBCD, which is configured for two-stage drying to optimize heat transfer. Before arriving at the FBCD, the air stream picks up additional heat from the unit flue gas through another heat exchanger. The twice-heated air stream then enters the FBCD. After picking up moisture from the coal, the moisture laden air stream passes through a dust collector to remove coal dust liberated during the drying process before being discharged to the atmosphere. Additional heat is added to the FBCD through coils fed with water heated by the unit's flue gas. This additional heat is added to the FBCD to optimize fluidized bed operating characteristics. After leaving the FBCD, dried coal enters a coal storage bunker (not shown) before being sent to a pulverizer for size reduction prior to being delivered to the boiler.

The GRE project at CCS was implemented in two phases. The first phase of the project involved the installation and operation of one prototype dryer, rated at 112.5 tons/hour (225,000 lb/hour) capacity. The prototype dryer was designed to reduce the lignite moisture content from 38 percent to 29.5 percent, which corresponds to an increase in higher heating value from 6,200 Btu/lb to 7,045 Btu/lb.

The prototype coal drying system was designed with completely automated control capability, which included startup, shutdown, and emergency shutdown sequences. The heat input to the FBCD is automatically controlled to remove a specified amount of moisture from the lignite feed stream.



Schematic of Lignite Coal Drying Process

Following the prototype dryer installation and startup, around-the-clock operations and data collection began in March 2006. The moisture content of the lignite processed through the prototype coal drying system was reduced from about 38.5 percent to 29.5 percent. In addition to the measured reductions in SO_X, NO_X, and CO_2 emissions in the flue gas, two modes of Hg reduction were also achieved. First, the heavy components of lignite that were collected in the first stage of the dryer (and removed) possessed a higher Hg concentration, reducing the amount of Hg in the coal fed to the boiler. In addition, Hg oxidation was enhanced as coal moisture was reduced, thereby facilitating additional capture in the flue gas desulfurization unit. Both modes of reduced Hg emissions were confirmed with semi-continuous emission monitors at the inlet and outlet of the flue gas desulfurization unit.

GRE initiated design activities for full-scale dryers (135 tons/hr) in September 2006, which incorporated lessons learned from prototype operation. The full-scale dryer system design was completed in December 2007 and GRE subsequently installed four dryers on Unit 2. Due to the success of the prototype demonstration, GRE installed four more dryers on Unit 1 with its own funds. The final result was that Unit 1 and Unit 2 of the CCS were simultaneously retrofitted with lignite coal dryers.

Fabrication and on-site assembly were finished in May 2008 and major dryer internal components for the Unit 2 dryers were completed by December 2008. GRE completed the construction of the dryer system and began testing in late 2009.

Results

The project achieved the goal of lowering the moisture content of the lignite by 8.5 percentage points (approximately one fourth of the as-received moisture). Test results were obtained from the technology installed on Unit 1, which is identical to that of Unit 2. Unit 2 was out of service at the time of testing for reasons not associated with the lignite drying technology. During performance testing, Unit 1 provided the combined station load for Units 1 and 2 while also supplying extraction steam for an auxiliary process. This plant configuration resulted in an efficiency impact to the testing results that could not be accurately extrapolated to periods of normal operation. While those particular data could not be obtained by GRE, other data for moisture reduction and emissions were obtained.

The demonstrated 8.5 percent moisture reduction of the lignite resulted in an HHV improvement in the fuel from 6290 Btu/lb to 7043 Btu/lb. Also demonstrated were emissions reductions in Hg by 41 percent, NO_X by 32 percent, and SO_2 by 54 percent.

Benefits

Reducing the coal moisture content improved the lignite HHV, which arguably reduced unit heat rate. This improvement was due primarily to lower stack loss and decreased auxiliary power use (e.g., lower fan, pulverizer, cooling tower, and coal handling power). As the boiler efficiency increases and the auxiliary power requirement was reduced, additional electrical energy was available for export to the grid. The reduction in coal flow rate also produced an incremental improvement in coal handling and processing equipment wear rates, which resulted in a maintenance-related cost benefit.

Performance of the back-end environmental control systems (i.e., electrostatic precipitator) also improved with the use of reduced moisture coal in the furnace. The reduction in coal flow rate to the boiler resulted in a lower flue gas flow rate that gave the flue gas a longer residence time within the emissions control equipment, incrementally improving its performance. Similarly, the reduction in required coal-flow rate to the boiler and the resulting modified temperature profile within the boiler directly translated into lower emissions of NO_X, SO_2, and particulates. While not directly measured, CO_2 emissions were calculated to have been decreased by approximately 3.8 percent. Units equipped with wet scrubbers also exhibited a reduction in Hg emissions resulting from firing reduced moisture coal. This reduction resulted from an increase in the oxidation of elemental Hg to forms that can be removed in a scrubber.

A potential benefit of the coal drying system for new plants would be a reduction in capital costs. A decrease in the coal firing rate could result in smaller capacity requirements for coal handling and coal processing systems as well as those associated with combustion, flue gas transport, and flue gas cleaning.

The potential market for GRE's coal-drying technology is significant. Currently, more than 100 GW of U.S. installed capacity is burning coal with inherently high moisture content. This technology could not only reduce emissions from coal-fired power plants, but also extend abundant U.S. coal supplies, thereby enhancing the nation's energy security.

In 2009, GRE signed an agreement with Worley Parsons, an engineering firm, giving them preferred engineer status to license DryFining™, the trademark name for the technology. GRE will also process and ship DryFined coal to the Spiritwood Station nearing completion 10 miles east of Jamestown, North Dakota. By the conclusion of the project, GRE had 120 confidentiality agreements signed by vendors and suppliers of equipment and 19 by utilities. Companies in the United States, Canada, Australia, China, India, Indonesia, and Europe have signed GRE confidentiality agreements. These agreements are required before GRE will provide details of the technology to interested parties. In addition, three preliminary evaluations have been completed that show the comparative improvements that can be realized at those stations. DryFining™ earned the "Best Coal-Fired Project" award for 2010 from the editors of the prestigious *Power Engineering* magazine.

Conclusions

The operation of full-scale lignite drying equipment was demonstrated and the remaining project performance goals were met, which included an improvement in lignite quality and the reduction of emissions.

Typical PRB Coal Analysis

Property	Typical Value
Higher Heating Value, Btu/lb	9,052
Analysis, Weight Percent	
Moisture	25.85
Carbon	52.49
Hydrogen	3.65
Nitrogen	0.75
Sulfur	0.28
Ash	4.64
Oxygen	12.33
Chlorine	0.01

TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers

Introduction

Powder River Basin (PRB) coal has become widely used and is typical of other western subbituminous coals in that it produces a high percentage of elemental mercury (Hg) in the flue gas upon combustion. Elemental Hg is more difficult to remove from the flue gas stream than solid state oxides of Hg (the form more common in bituminous coals). The injection of powdered activated carbon (PAC) into the flue gas stream for Hg capture is one promising control technology.

A potential disadvantage of injecting PAC for Hg control in plants where PAC injection occurs upstream of the particulate control system is its impact on the salability of ash for making concrete. If the ash cannot be sold, it must be sent to a landfill, which increases the plant's operating costs and decreases available disposal capacity. The TOXECON™ configuration injects the activated carbon downstream from the primary ash collection equipment, thus ensuring the ash remains acceptable for sale.

DOE selected the TOXECON™ technology in 2003 as a CCPI-1 Hg control demonstration project. The demonstration was carried out at Wisconsin Electric Power Company's (We Energies) Presque Isle Power Plant (PIPP) located in Marquette, Michigan.

The total project cost was $47,512,830 with DOE providing $23,756,415 or 50 percent. We Energies provided the remaining 50 percent. NEPA was satisfied with a FONSI in September 2003. The demonstration began operation in January 2006 and was completed in September 2009.

Project Objectives

The project objectives were to demonstrate, over the long-term (three years), 90 percent removal of Hg from power plant flue gas using activated carbon injection; demonstrate a reliable Hg continuous emission monitoring system (CEMS) suitable for use in flue gas created by coal-fired power plants; advance commercialization of the technology through successful operation and integration with the power plant; evaluate trona (a naturally occurring sodium bicarbonate mineral) injection to reduce NO_x and capture 70 percent of SO_2 emissions via the new bag house; demonstrate recovery of Hg from the spent sorbent; reduce particulate matter (PM) emissions via the new bag house; and allow the continued reuse and sale of fly ash captured by the existing hot-side ESP.

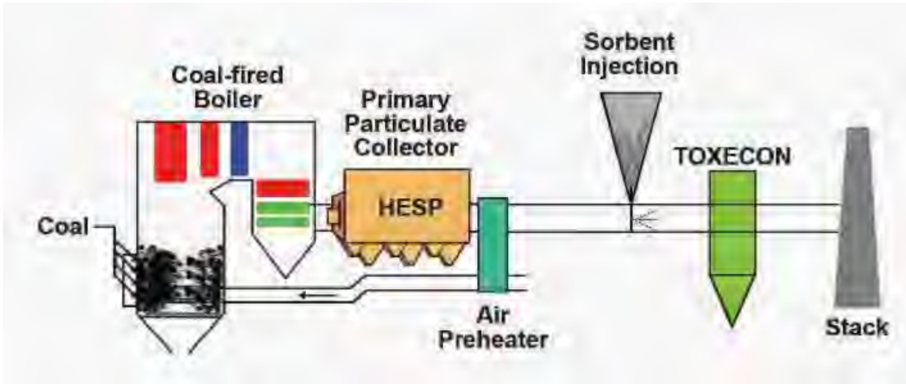
Project Description

The TOXECON™ demonstration technology was installed on the combined flue gas streams of PIPP Units 7, 8, and 9, which are rated at 90 MW each. There are a total of nine units at the PIPP site that were installed between 1955 and 1979. Units 7, 8, and 9 are of the Riley Turbo design and are dry-bottom, opposed-wall-fired boilers. Steam conditions at the superheater are 1625 psig and 1005 °F, and conditions at the reheater are 390 psig and 1005 °F. Each of the three units is equipped with Joy-Western hot side electrostatic precipitators (ESPs). NO_x emissions are managed with low-NO_x burners and a combustion optimization software package. SO_2 emission limits are met on Units 7, 8, and 9 by burning low sulfur PRB coal. The coal typically has an HHV of 9,052 Btu/lb, a sulfur content of 0.28 percent, and an average Hg content of 0.13μg/g.

For the demonstration at PIPP, the TOXECON™ technology was installed downstream of the air preheater. The TOXECON™ process consisted of two systems that included (1) a sorbent injection system that includes the in-duct injection lances and the sorbent receiving, handling, and storage facilities; and (2) a baghouse with secondary systems for ash removal and supplying compressed air for bag cleaning.

The TOXECON™ technology is intended for installation in a downstream location from an existing cold-side or hot-side ESP. When applied to a host plant that is configured with a hot-side ESP, the TOXECON™ system is installed immediately downstream of the air preheater. In the case of a cold-side ESP installation, the TOXECON™ system is located just downstream of the ESP.

Presque Isle Power Plant



TOXECON™ Flow Schematic at PIPP

The TOXECON™ installation at PIPP was relatively simple. The PAC system consisted of storage, transport, and injection subsystems. Because the PIPP installation includes a hot-side precipitator, PAC is injected downstream from each of Units 7, 8, and 9 air preheaters through three separate trains. The design and location of the PAC injection lances ensure thorough mixing of the PAC sorbent with the flue gas.

Each of the three PAC duct injection trains handled 200 lb/hr of sorbent material and consisted of a feed hopper, feeder, eductor, injection lance, and blower. The design injection rate of 216 lb/hr permitted optional reinjection of some PAC/fly ash from the baghouse. A similar injection train was also installed to evaluate the effectiveness of a sodium-based sorbent for the removal of 70 percent of SO_2 as well as some NO_X. After the sorbents were injected into the flue gas from Units 7, 8, and 9, the flows were directed to a single duct leading to the baghouse. Flue gas leaving the baghouse splits into three streams and is discharged through three separate flues enclosed by a single stack.

The PAC entrained in the flue gas captured some of the Hg present as the gas stream traveled to the baghouse. Once in the baghouse, the PAC and residual fly ash were removed from the gas stream by forming a dust cake layer on the surface of the bags. The PAC in the dust cake continued to remove Hg from the gas stream as long as it remained on the bags, which was also the case when sodium-based sorbent was used for SO_2 and NO_X control. Because removing the dust cake layer

TOXECON™ System Installed at PIPP

reduced collection efficiency, the design and operation of the baghouse maximized the amount of time the dust cake remained on the bags within the limits of sound operating practices.

At the beginning of the project in 2003, there were no Hg continuous emission monitors (CEMs) available that had Environmental Protection Agency (EPA) certification and could be operated independent of full-time technical support. As part of the project, Hg CEMs were developed and tested that could be reliably used in the power plant environment and measure Hg with good sensitivity.

Two thermal laboratory-scale technologies having the potential to remove Hg from TOXECON™ baghouse ash were identified during the first quarter of 2008. One of the processes used microwave energy as the energy source while the other used heated air. Both methods were reported to exceed 90 percent recovery of Hg from the baghouse ash in laboratory tests.

One laboratory study irradiated ash with microwave energy for three minutes under a nitrogen gas flow. The evaporated Hg was carried by the gas flow to a condenser. Mercury that was not condensed was scrubbed from the nitrogen with a potassium permanganate solution.

The second technology used a chemical absorbent to chemically capture Hg while it was in the gas phase. The chemical absorbent developed for this study exhibited excellent Hg capture performance; however, it proved too expensive for commercial applications. Subsequently, a commercially produced absorbent was identified and tested. The commercially available absorbent captured the Hg that was released from the fly ash by thermal desorption. The resulting sorbent/Hg material was found to be both thermally and chemically stable, presenting no risk to the environment.

Results

TOXECON™ performance testing confirmed a reliable minimum Hg removal rate of 90 percent from the flue gas leaving the hot-side ESP. This performance was verified using several different types of PAC. During testing, Hg removal was observed to vary inversely (linear) with baghouse temperature, which is a well-documented correlation in the TOXECON™ baghouse.

The goal of developing a reliable Hg CEM capable of operating in a power plant environment was met. Toward the conclusion of the demonstration, the CEM developed by Thermo Fisher and ADA-ES exhibited high availability for monitoring Hg at the inlet and outlet duct. It is commercially available from Thermo Fisher and has reportedly been selling well.

The baghouse and associated equipment were successfully integrated into plant operations. The spent PAC handling equipment was upgraded and the operation of the system was optimized during the demonstration project. Early in the project, there was a problem with hot embers/fires in the baghouse hoppers. A combination of laboratory work and operational adjustments corrected the problem and there was no recurrence during long-term testing.

Sulfur dioxide and potential NO_X removal rates were investigated by injecting trona ($Na_3H(CO_3)_2 \cdot 2H_2O$), a sodium-based sorbent, into the flue gas stream. While the goal of 70 percent SO_2 removal was met, there was no perceptible impact on NO_X emissions. When both trona and PAC were injected simultaneously, Hg removal efficiency decreased significantly, with a slight (approximately one percent) effect on opacity. Even with an increase in the brominated PAC injection rate [1.5 lb/MMacf (million actual cubic feet) to 4.5 lb/MMacf], achieving 90 percent Hg control while maintaining 70 percent SO_2 removal could not be consistently achieved.

The goal to recover 90 percent of Hg captured in the sorbent was met in laboratory tests. The Hg content in the consumed sorbents was reduced from 14.8 ppm to 0.252 ppm (98.3 percent reduction) after the microwave treatment methodology, which was one of the two methods identified to accomplish this goal. The other process used a natural gas-fired kiln and reduced the Hg content from 31 ppm to a level that was not measureable. The Hg released during these tests was captured by another process, leaving the sorbent and fly ash to be constructively reused.

The goal of increasing the plant's collection efficiency of PM [particularly for $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter)] was met due to the high capture efficiency of the baghouse.

The utilization goal for fly ash captured in the hotside ESP was met due to the introduction of PAC downstream of the primary particulate control device. While the actual utilization of fly ash was outside the scope of the project, the project goal to enable fly ash utilization by preserving its quality was met.

CONTROLLING MERCURY

While research continues to find better and cheaper ways to remove mercury from the flue gas of coal-fired boilers, electric generating units (EGUs) already have several viable options. The mercury found in flue gas can be found in several physical and/or chemical states. It can be in the form of elemental mercury vapor or in an oxidized state. These chemical states can either be attached to fly ash particles or free-floating. No matter which technology is used, elemental mercury is more difficult to remove than oxidized mercury.

The current leading technology specific to mercury removal consists of injecting powdered activated carbon (PAC) into the flue gas to adsorb the mercury. In some cases, the system itself is very simple, consisting of equipment to receive, handle, store, and inject the carbon. The carbon is injected into the flue gas between the air heater and the particulate control device. The particulate control device, either a baghouse or an electrostatic precipitator, removes the carbon and adsorbed mercury along with the fly ash. Continued use of the existing baghouse or ESP assumes that the existing particulate control device can handle the additional particulate load without degradation of performance. A disadvantage of this simple system is that the fly ash is contaminated with activated carbon. In 2004, approximately 40 percent of the fly ash was sold for constructive uses. Fly ash with high carbon content is difficult to sell and EGU operators are reluctant to risk losing their market, since they would incur disposal costs rather than receive payment for the fly ash. If the boiler being retrofitted with activated carbon injection (ACI) is equipped with a hot-side ESP, the power plant can install the ACI system downstream of the air heater and install a new particulate removal system to remove the PAC and any residual fly ash. A baghouse is generally preferred due to its high efficiency, especially for respirable particulates. This method ensures that the bulk of the fly ash removed by the existing ESP is not contaminated with additional carbon.

While ACI is the most effective method of capturing mercury, power plants can often achieve significant coincidental mercury removal with their particulate and SO2 controls. The effectiveness of achieving adequate mercury removal in equipment intended to control other pollutants varies significantly from plant to plant. As stated above, elemental mercury is less likely to be captured by any removal system, although ACI is less sensitive to the state of the mercury. The state of mercury in flue gas is affected by the type of boiler and coal and variations in boiler operation. Operators can influence the state of mercury in the boiler by optimizing combustion conditions to maximize oxidation of the mercury while maintaining satisfactory overall operation. By increasing the portion of the mercury that is oxidized, its removal in the ESP, baghouse, and/or flue gas desulfurization (FGD) system is enhanced.

Increased oxidation of mercury is also a co-benefit of a selective catalytic reduction (SCR) system. The SCR catalyst tends to oxidize a portion of the mercury in the flue gas, leading to higher removal rates in the particulate control system and/or the FGD system.

Benefits

The TOXECON™ process provides a technology pathway to significant Hg control and has the potential to widen the use of PRB, as well as other western subbituminous coals, especially in light of the Mercury and Air Toxics Standards (MATS) established in December 2011. Additional benefits are derived from the inherently high particulate removal efficiency of a baghouse. While trona injection resulted in a 70 percent reduction of SO_2, concurrent PAC/trona injection greatly reduced previously demonstrated Hg removal efficiency. However, it is anticipated that other sorbents will be able to be used to further control pollutants and be complementary to Hg removal efficiency.

The TOXECON™ process was configured to treat the plant flue gas after the bulk of fly ash is captured in the HESP, thus preserving its quality for use as a concrete additive as well as for other beneficial uses. A secondary benefit is the preservation of landfill capacity, as the fly ash will have a beneficial use and not require disposal.

As part of the TOXECON™ process design, the baghouse downstream of an existing ESP removes the injected sorbent and the adsorbed pollutants. An additional benefit of this configuration is the significant reduction of both $PM_{2.5}$ and $PM_{2.5}$ precursor emissions (e.g., SO_2).

The TOXECON™ process is considered suitable for application on 167 GW of coal-fired generating capacity and may prove to be the primary Hg control choice for western coals, especially when fired in units having hot-side ESPs. TOXECON™ systems were installed at seven plants in addition to PIPP. Although exact numbers are not available, it has been reported that a substantial market has developed for the Hg CEMS developed during this project. When the CAMR was vacated by the courts, there was uncertainty regarding the final Hg rule, which likely led to power plants deferring their decision on the selection of an Hg control technology. The final standards for Hg were published in mid-February 2012. The success of the TOXECON™ demonstration has provided the owners of those 167 GW with a viable technology to meet the three year deadline for compliance with the new Hg standard.

Conclusions

The TOXECON™ process demonstrated significant Hg control for units having a hot-side ESP and firing a western subbituminous coal. The technology should be applicable to all coal-fired power plants. The placement of the TOXECON™ baghouse downstream of the existing ESP preserved fly ash quality for beneficial use while removing Hg from the plant flue gas stream. Fly ash that is used constructively will not require disposal in a landfill, thereby eliminating disposal costs and conserving landfill space. The baghouse also removed much of the very fine particulate that passed through the ESP.

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CCPI-1 Program Conclusions

The goal of CCPI-1 was to "*advance technology related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives*." The three projects discussed in this report have directly contributed to the CCPI objectives through more efficient operation that extends the nation's abundant coal reserves, further reduces emissions, resulting in cleaner air, and lowers generation costs, which can help to keep electricity affordable. Below is a brief summary of the contributions of each CCPI-1 project.

- The plant optimization capability developed during the course of the Demonstration of Integrated Optimization Software at the Baldwin Energy Complex project could benefit many types of power plant boilers. The NO_x reduction target of five percent was exceeded and actually reached the 12 to 14 percent range, while heat rate improvement only reached half of the targeted improvement. However, the improvement achieved in heat rate should translate into slightly lower fuel consumption (and hence fuel cost) with a commensurate decrease in overall emissions. The demonstrated environmental, efficiency, and cost improvements confirm that the project has met the CCPI-1 program goals.

- The GRE Increasing Power Plant Efficiency: Lignite Fuel Enhancement demonstration has shown benefits from the full-scale coal drying system at Coal Creek Station (CCS) that utilizes waste heat. Lignite quality has improved and plant emissions have decreased due to a reduction in the amount of lignite being burned and the reduced Hg content of the fuel brought about by the density separation in the first drying stage. An additional benefit for new plants could be a reduction in capital costs due to subsystems being favorably impacted by decreased plant fuel requirements. These advancements demonstrate that CCPI-1 program goals have been achieved.

- TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90-MW Coal-Fired Boilers controls Hg and other pollutants in the flue gas stream with sorbent injection while preserving the marketability of the captured fly ash. A reliable Hg CEM, capable of withstanding harsh power plant conditions, was also developed during this project. The results obtained from this project contribute to the achievement of the CCPI-1 program goals.

The application of technologies resulting from the DOE CCPI-1 solicitation will help resolve environmental concerns regarding the increased use of coal. These contributions to coal's viability will help ensure that the United States continues to generate clean, reliable, and affordable electricity from this plentiful and valuable resource.

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Acronyms and Abbreviations

ACI	Activated Carbon Injection
AI	Artificial Intelligence
ARRA	American Recovery and Reinvestment Act
BEC	Baldwin Energy Complex
BTU	British thermal unit
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCPI	Clean Coal Power Initiative
CCS	Coal Creek Station
CCT	Clean Coal Technology
CCTDP	Clean Coal Technology Demonstration Program
CE	Combustion Engineering
CEM	Continuous Emissions Monitor
CO_2	Carbon dioxide
DOE	Department of Energy
EA	Environmental Assessment
EPRI	Electric Power Research Institute
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FBCD	Fluidized Bed Coal Dryer
FBD	Fluidized Bed Dryer
FE	Office of Fossil Energy
FGD	Flue Gas Desulfurization
FL	Fuzzy Logic
FONSI	Finding of No Significant Impact
g	Gram
GRE	Great River Energy
GW	Gigawatt
HAPS	Hazardous Air Pollutants
Hg	Mercury
HHV	Higher Heating Value
ICR	Information Collection Request
Lb	Pound
MATS	Mercury and Air Toxics Standards
MMacf	million actual cubic feet
NAS	National Academy of Sciences
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NH_3	Ammonia
NN	Neural Network
MW	Megawatts
MWh	Megawatt-hours
NO_X	Nitrogen Oxides
PAC	Powdered Activated Carbon
PIPP	Presque Isle Power Plant
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 microns in diameter
PPII	Power Plant Improvement Initiative
PRB	Powder River Basin
PSIA	Pounds per Square Inch Absolute
R&D	Research & Development
SCR	Selective Catalytic Reduction
SO_2	Sulfur dioxide
µg	Microgram
U.S.	United States
We Energies	Wisconsin Electric Power Company

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Exhibit 2

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, LIGNITE ENERGY COUNCIL, NATIONAL MINING ASSOCIATION, MINNKOTA POWER COOPERATIVE, INC., EAST KENTUCKY POWER COOPERATIVE, INC., ASSOCIATED ELECTRIC COOPERATIVE INC., BASIN ELECTRIC POWER COOPERATIVE, and RAINBOW ENERGY CENTER, LLC,	)	Case No. 24-1179
Petitioners,	)	
v.	)	
U.S. ENVIRONMENTAL PROTECTION AGENCY and MICHAEL S. REGAN, in his official capacity as Administrator of the U.S. Environmental Protection Agency,	)	
Respondents	)	

DECLARATION OF CRAIG COURTER OF SAN MIGUEL ELECTRIC COOPERATIVE, INC. IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

I, Craig Courter, declare:

1. My name is Craig Courter. I am the General Manager for the San Miguel Electric Cooperative, Inc, which is located in Atascosa County, Texas. I am over the age of 18 years and am competent to testify concerning the matters in this declaration. Except where specifically noted below, I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. In my capacity as General Manager for San Miguel, I am responsible for general oversight of the Cooperative to ensure fulfillment of San Miguel's mission "to maintain a

dependable power supply at the lowest possible and competitive cost to our customers through integrity, hard work, and safety." This encompasses the overall day-to-day maintenance of the economic and technical profile of the Cooperative including plant performance, reliability, fuel sufficiency, and financial integrity. San Miguel's Board of Directors chooses the General manager and oversees the performance of the General Manager.

3. I have more than 36 years of experience in electricity generation. I have been employed at San Miguel since August of 2021. I started as the Plant Manager and transitioned to General Manager in October of 2022. I hold a Bachelors of Business Management, Master of Business Administration from Western Governors University Texas and have a background in engineering and chemistry as I am a specialist in online analytical instrumentation—specifically in continuous emissions monitoring analyzers used for measuring emissions from coal and natural gas combustion turbines.

4. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's (EPA) National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review (the Final Rule or the MATS Rule).

Background on San Miguel

5. San Miguel was created on February 17, 1977, for the purpose of owning and operating a mine-mouth, lignite coal-fired generating plant and associated lignite coal-mining facilities. San Miguel is a not-for-profit electric cooperative, small business entity, incorporated in the State of Texas under the Electric Cooperative Corporation Act, Tex. Uit. Code, Chapter 161.

San Miguel exists for the purpose of owning and operating the generating plant and associated lignite coal-mining facilities.

6. A "mine-mouth" power plant, like the one operated by San Miguel, is a power plant that is located "at the mouth of a mine," *e.g.*, adjacent to a mine. "Lignite" is a recognized rank of coal that is distinct from other ranks of coal such as "bituminous," "sub-bituminous," and "anthracite." Lignite is frequently utilized at mine-mouth power generation facilities and is used by San Miguel. Lignite is fundamentally different from the other ranks of coal. Generation of electricity from lignite is technologically, chemically, physically, and functionally distinct from these other ranks of coal. These distinctions have been recognized by industry, regulators, and by EPA itself. Lignite-fired power plants are technologically and operationally distinct from traditional coal-fired power plants and include different design elements that warranted and resulted in a separate subcategory within the overarching coal category.

7. San Miguel is owned and democratically governed by its members through its Board of Directors. The Board is made up of 19 Directors who represent South Texas Electric Cooperative ("STEC") and its 9 respective distribution cooperatives. STEC is a 1,865.2 MW generation and transmission cooperative whose members' service territory extends across 47 counties through South Texas.

8. San Miguel produces a net 391 MW of affordable, reliable electricity for its 9 member cooperatives—enough electricity to power more than 78,000 homes during peak demand. When many Texas power generators were shut down during Winter Storm Uri in 2021, San Miguel continued supplying power to the Texas electrical grid.

9. San Miguel has entered into a Wholesale Power Contract with the STEC. The Wholesale Power Contract does not terminate until 2037 and requires STEC to purchase San

Miguel's entire output. The Wholesale Power Contract may be extended for a longer period of time. Other than the Wholesale Power Contract and some transmission revenues, San Miguel has no other sources of revenue.

10. San Miguel is a member of the National Rural Electric Cooperative Association (NRECA). NRECA represents the interests of rural electric cooperatives across the country.

11. The MATS Rule threatens all lignite-powered plants, including San Miguel, by forcing them to install expensive equipment to meet the regulatory requirements of the Rule at the expense of the ratepayers. It also threatens the reliability of the entire grid across Texas, places burdens on the power sector as a whole, and causes harm to industries dependent on a reliable electric grid.

12. If the MATS Rule goes into effect, San Miguel will be forced to make large expenditures to satisfy the Rule in close proximity to its anticipated closure in 2037. This will negatively affect San Miguel's financial planning, which does not contemplate such largescale expenditures so close to the scheduled retirement. If the Rule is not stayed, San Miguel's Board would need to immediately begin building compliance costs into its rates for electricity. It would have no other choice given the impending closure date in 2037 and high costs of compliance.

Summary of MATS Rule

13. The MATS Rule eliminates the low rank coal subcategory for lignite-powered facilities and changes the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the New Mercury Limitation).

14. The MATS Rule decreases the limit for filterable particulate matter (fPM) to 0.010 lbs/MMBtu (the New fPM Limitation).

15. Compliance with the New Mercury and New fPM Limitations is required on or before three years after the effective date of the Final Rule.

16. The MATS Rule provides that Continuous Emission Monitoring Systems (CEMS) are the only method to demonstrate compliance with the fPM limit.

EPA relies on faulty data to support the MATS Rule.

17. For both mercury and particulate matter, EPA's proposed reductions to the applicable emission limits are based on data that is simply incorrect or fails to acknowledge how emission control technologies actually work.

18. The Rule provides that the proposed reduction in the mercury limit for lignite-fired units is based on information provided to the Energy Information Administration and by using the information collection authority provided under Clean Air Act section 114. Table 7 shows the Hg Inlet level which reflects the maximum mercury content of the range of feedstock coals that the EPA assumes is available to each of the plants in the Integrated Planning Model ("IPM"). 89 Fed. Reg. 38548. In Table 7 of the Rule, EPA states that the mercury inlet concentration at San Miguel is 28.9 lb/TBtu. *Id.* This data is simply wrong.

19. San Miguel provided information to EPA in response to a 114 Information Request, which shows the average mercury inlet concentration to be 34 lb/TBtu. Furthermore, this is not a snapshot or cherry-picked data; this is the average concentration going back to 2011—more than a decade's worth of data. San Miguel made this information available to the EPA in its comment letter, attached as Exhibit A to this declaration. *See* Ex. A, San Miguel Comment Letter, at 5-6.

20. EPA's incorrect data fails to recognize the highly variable mercury content of lignite. The highest mercury inlet concentration at San Miguel since 2011 was as high as 69 lb/TBtu. On the other hand, the lowest recorded mercury inlet concentration at San Miguel in over

a decade was 23 lb/TBtu, only slightly lower than the number the EPA uses to justify its mercury limit.

21. San Miguel has recently averaged around 25-29 lb/TBtu inlet mercury—still above the maximum rate that the EPA used in its analysis presented in Table 7. With the variable inlet mercury content in its fuel, meeting the current 4.0 lb/TBtu emission standard requires constant focus. Maintaining compliance with the 1.2 lb/TBtu in the MATS Rule—an emission limit that is 70% lower than the current standard—is not feasible and, as detailed above, is not supported by the data.

22. The full range of actual inlet conditions indicates San Miguel would need around a 94% mercury removal rate to achieve the current 4.0 lb/TBtu emission standard and would need around a 98% mercury removal rate to achieve the proposed 1.2 lb/TBtu emission standard. This level of removal is well above the performance assumed by the EPA to achieve compliance. Furthermore, San Miguel would need to target a lower emission rate, like a 1.0 lb/TBtu limit, to achieve compliance over the entire 30-day rolling average period.

EPA incorrectly assumes that emission control efficiency for other coal categories is equivalent to that for lignite.

23. EPA also wrongly equivocates lignite and other coal categories. 89 Fed. Reg. 38541 The Rule states, "Subbituminous coals also have low natural halogen content and high fly ash alkalinity. Eastern and central bituminous coals also have high sulfur content. Bituminous and anthracitic waste coals (coal refuse) have very high and variable Hg content. EGUs firing any of these non-lignite coals have been subject to—and have demonstrated compliance with—the more Stringent Hg emission standard of 1.2 lb/TBtu." *Id.*

24. EPA appears to have ignored the findings in a 2013 technical report prepared by Sargent & Lundy that was prepared for EPA to analyze mercury controls (the "S&L Report"). The

report directly contradicts EPA's supposition that lignite-fired units should be able to meet the same standard as subbituminous units.[1] The S&L Report describes in detail how activated carbon injection is rendered significantly less effective when the flue gas contains SO_3, stating:

> Some flue gas constituents, especially SO_3, reduce the mercury removal effectiveness of both activated carbon and non-carbon sorbents. With flue gas SO_3 concentrations greater than 5 - 7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, the capacity of activated carbon can be cut by as much as one-half with an SO_3 increase from just 5 ppmv to 10 ppmv.

The higher sulfur content of lignite equates to greater production rates of SO_3. Texas lignite units often have high flue gas SO_3 concentrations and could be considered medium- to high-sulfur coals based on pounds of SO_2 produced per million Btu of heat input. Gulf Coast lignite generally features higher sulfur content—by a factor of two or more. Notably, Texas lignite is disadvantaged as the alkalinity to sulfur ratio is half that of Powder River Basin coal.

25. As to San Miguel, since 2017, the sulfur percentage of the lignite fuel ranges from a minimum of 1.31% to a maximum of 3.42%. The lignite fuel used at San Miguel during that time period had an average of 2.48% sulfur content. Based on a fuel analysis conducted in 2014, San Miguel has an average sulfur content of 9.6 lb/SO_2 per million Btu.

26. When EPA set its emission limits for lignite-fired EGUs, EPA simply assumed such units would be fully capable of meeting the same standard as units firing other forms of coal. In

[1] *IPM Model: Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology,* Sargent & Lundy, Project 12847-002 (March 2013).

so doing, EPA has not only failed to recognize the difference in sulfur content of various coal veins, but has also failed to observe the significant impact of certain flue gas constituents on the effectiveness of activated carbon injection as a means to control mercury emissions.

Proposed fPM limits are not achievable.

27. Particulate at San Miguel is captured and removed from the flue gas path primarily by the existing electrostatic precipitators ("ESPs"). The wet flue gas desulfurization ("WFGD") system downstream of the ESPs will also capture some of the particulate that makes it through the ESPs. The effectiveness of the existing ESPs and WFGD system to control PM emissions is demonstrated by the data in Table below. San Miguel works extremely hard to maintain compliance with this standard. Compliance with the fPM emission limit of 0.01 lb/MMBtu will be marginal under even the best operating scenarios.

	Measured fPM 0.03 lb/MMBtu current limit	Margin with 0.01 lb/MMBtu limit	Percent Margin (%)
min	0.00600	0.00400	40.0%
5th percentile	0.00614	0.00386	38.6%
average	0.03266	-0.02266	-226.6%
95th percentile	0.16411	-0.15411	-1541.1%
max	0.23300	-0.22300	-2230.0%

28. To achieve compliance with the 0.01 lb/MMBtu limit, San Miguel has to consider several options including: 1) ESP upgrades, 2) full fabric filter downstream, 3) reduced size fabric filter downstream, and 4) an ESP to fabric filter conversion. As detailed below, these are expensive systems. And San Miguel would have until only 2037 to repay those costs, at which time it will cease generating revenue due to the expiration of the Wholesale Power Contract.

To meet the new standards, San Miguel would have to make millions of dollars in upgrades.

29. To even attempt to meet the standards in the MATS Rule, San Miguel would need to make costly upgrades to its systems. In its comments to the Proposed Rule, San Miguel included a list of the estimated capital and O&M costs, which is reprinted below.[2]

High Estimate	Capital	O&M	NPV	Total Levelized Cost
Option	**(2024$)**	**(2024$)**	**(2024$)**	**$/yr (2024$)**
New Mercury Controls	$10,800,000	$12,745,000	$213,493,000	$21,126,000
New Baghouse	$160,000,000	$4,220,000	$209,671,000	$20,747,000
New Particulate CEMS	$1,950,000	$25,000	$2,133,000	$211,000

Low Estimate	Capital	O&M	NPV	Total Levelized Cost
Option	**(2024$)**	**(2024$)**	**(2024$)**	**$/yr (2024$)**
New Mercury Controls	$8,100,000	$10,631,000	$177,277,000	$17,542,000
New Baghouse	$130,000,000	$3,430,000	$170,378,000	$16,859,000
New Particulate CEMS	$1,450,000	$25,000	$1,688,000	$167,000

30. The basis for the cost estimate includes a new liquid chemical feed system and new dry sorbent storage and injection system. The liquid chemical feed system includes a bulk 10,000-gallon SF-20 liquid storage tank to provide a 14-day supply of chemical plus 2 x 100% capacity liquid chemical feed pumps assembled on a common chemical feed skid inside a shop-fabricated enclosure.

31. The dry chemical feed system includes a new 500-ton storage silo plus 2 x 100% capacity blowers, piping, instrumentation, and valves necessary to inject the sorbent material into the flue gas duct. We have estimated the installation cost for the new mercury control equipment to be in the range of $8.1 M to $10.8 M.

[2] Ex. A, Comment Letter at 9. This assumes a project start date of 2024 and plant retirement date of 2040, assuming that the Wholesale Power Contact is extended by three years. An inflation rate of 3 percent and discount rate of 6 percent were used.

32. Annual operating cost calculations were completed on the SF-20 and SB-31 injection rates needed to achieve 1.2 lb Hg/TBtu based on the historical average mercury concentration of 34 lb/TBtu. An SF-20 injection rate of 30 gal/hour was assumed along with an SB-31 injection rate of 1,200 lb/h per vendor recommendations. Annual emissions for the last three years were obtained from the EPA—Clean Air Markets Program Data website to find the average capacity factor of approximately 81% over the past three years. SB-31 cost was assumed to be $1.15/lb which was the value used in the proposed MATS rule. The annual operating and maintenance cost of the mercury control system is estimated at approximately $10,631,000 - $12,745,000, or about $10,000/lb Hg removed.

33. Capital costs for the ESP upgrades are projected in the $20 M range. However, there is no way to know with any certainty if the ESP upgrades will be able to achieve compliance with the fPM limit of 0.01 lb/MMBtu on a continuous basis. As such, an ESP upgrade is not technically feasible for San Miguel.

34. A full-size baghouse installation has costs in the $130 M to $160 M range. The reduced size baghouse would fall around 10 to 20 percent lower in total installed cost ($98 M - $145 M). The ESP to fabric filter conversion would fall around 20 to 40 percent lower cost ($80 M – $130 M) than the full-size fabric filter and would require a 3 to 4 month unit outage.

35. These expenditures would have to be made to comply with the MATS Rule. But the new standards are not in response to any actual risk associated with the regulated emissions. EPA is imposing the new standards because operators like San Miguel have made the effort to comply with the prior standard. It appears as though EPA decided to be more stringent for the sole purpose of being more stringent. The costs are therefore unjustified.

36. Any costs associated with these upgrades will be paid by the customers of STEC. So, it is ultimately the rate payers in rural South Texas who will be footing the bill for these controls.

The MATS Rule creates immediate irreparable harm due to financial decisions that must be made immediately so they can be recouped through electricity rates.

37. Without a stay of the MATS Rule and the deadlines associated with it, San Miguel's board must immediately begin to make decisions without the benefit of knowing the Rule's legal fate. Because San Miguel's financial planning has been tied to a scheduled closure in 2037, it must recoup any expenditures for compliance with the Rule in a short period of time. And if those expenditures are ultimately shown to be based on an illegal Rule, it is San Miguel's ratepayers who will have been harmed. High compliance costs will affect the rates San Miguel charges the ratepayers—most of whom live in disadvantaged rural communities.

38. San Miguel currently has over $677 million in outstanding debt obligations. It's financial planning spreads the ratepayers' burden of covering that debt through 2037. If the Rule and its deadlines are not stayed and San Miguel has to incur compliance costs now, those compliance costs will also be passed along to ratepayers. Covering both the current debt obligations and exorbitant compliance costs will cause extreme financial burdens on ratepayers.

39. Because San Miguel also operates a mine, there are mining costs it must also consider. San Miguel's current mine plan includes a progression through 2037, including the opening of a new mining area in 2025. There are significant costs to opening a new mining area—primarily related to infrastructure. This includes costs for construction of ponds, all-weather roads, bridges, and overpasses and the installation of power lines for the draglines. Any additional investment made in opening the new area would be made at significant risk and add to the already significant debt and plant and mine closure obligations. If San Miguel opens the new area and the

MATS Rule is ultimately upheld, San Miguel would have a compressed time frame to recoup the associated costs. A stay of the Rule and its deadlines will help mitigate the cost by affording San Miguel certainty that it will be able to operate and generate critical revenues until 2029-2030, depending on how long the compliance deadlines are suspended.

40. San Miguel already has invested approximately $130 million in environmental controls. These controls were installed so San Miguel could meet the existing MATS standards and run until 2037. If the Rule and its deadlines are stayed pending the legal challenge, San Miguel will have more time to recoup that investment without the burden of adding additional compliance measures for a rule that is likely to be found unlawful.

41. In addition to the consequences to its ratepayers, there could be real consequences to local employment and the local tax base if the Rule is not stayed. San Miguel is directly responsible for over 419 jobs in addition to hundreds of contractor positions. It contributes more than $3.5 M annually in local taxes. The power plant and the mine indirectly support numerous other local businesses in Atascosa County. Given the dearth of jobs in this rural area, the extreme financial hardships caused by the Rule could shorten the life of San Miguel or require it to reduce staff. This will mean many families will have to relocate. This type of upheaval should not occur unless a court has entered a final judgment on the propriety of the MATS Rule.

42. The MATS Rule will cause irreparable harm to San Miguel's ratepayers as the high costs of compliance will be passed on to them. Many of those ratepayers live at or near the poverty level and cannot afford even modest increases in their electric bills. STEC, who is San Miguel's sole customer, serves some of the poorest counties in Texas and, indeed, in the United States.

43. Of the 47 counties STEC serves,

- 33 are in the 70th percentile or higher (U.S. ranking) in terms of "people of color,"
- 23 are in the 70th percentile or higher in terms of "low income," and
- 7 are in the 70th percentile or higher in terms of "unemployment rate."[3]

Because STEC serves areas with low population density, there are fewer customers to share in any increased costs. It is these customers who will be harmed if San Miguel is forced to pass on higher rates while the legal challenges to the MATS Rule are pending.

Conclusion

44. If the Rule is not stayed, the only way San Miguel and its members will not suffer harm during the pendency of the legal challenges to the Rule is if (a) San Miguel ignores the Rule and makes all business decisions as if the Rule never exited and (b) the Rule is struck down before the first compliance date in three years. A stay of the Rule and its deadlines will give San Miguel more time to get its financial house in order in the unlikelihood that the Rule—which is based on faulty data and improper comparisons—is upheld.

I declare under penalty of perjury that the foregoing is true and correct.

M C Carter

Craig Courter
General Manager
San Miguel Electric Cooperative

Dated: 6/11/24

[3] These statistics come from EPA's Environmental Justice Screening tool available at https://ejscreen.epa.gov/mapper/index.html?wherestr=texas. They reflect data as of June 10, 2024.

EXHIBIT A

P.O. Box 280, Jourdanton, Texas 78026 (830) 784-3411

SAN MIGUEL ELECTRIC COOPERATIVE, INC.

June 23, 2023

VIA efiling

Mr. Michael Regan
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington DC 20460

Re: EPA-HQ-OAR-2018-0794; National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

Administrator Regan:

San Miguel Electric Cooperative, Inc. ("San Miguel") appreciates this opportunity to comment on the U.S. Environmental Protection Agency's ("EPA" or "Agency") proposed rule to update the National Emission Standards for Hazardous Air Pollutants ("HAP") for Coal- and Oil-Fired Electric Utility Steam Generating Units ("EGUs"), commonly known as the Mercury and Air Toxics Standards or ("MATS Rule").

INTRODUCTION

San Miguel is a 400 MW, mine-mouth, lignite-fired EGU located in Atascosa County, Texas. San Miguel is a not-for-profit electric cooperative created on February 17, 1977, under the Rural Electric Cooperative Act of the State of Texas. One hundred percent of the output of the plant is sold to San Miguel's member rural electric cooperatives through the South Texas Electric Cooperative ("STEC"). The electricity that San Miguel produces powers approximately 200,000 rural Texas homes in 45 South Texas counties.

San Miguel is proud of the accomplishments that have been achieved by power plant operators, state regulators, and EPA over the years striking a balance between energy and societal needs and environmental improvement.

BACKGROUND: LIGNITE SUBCATEGORIZATION

Lignite is fundamentally different from the other ranks of coal, including bituminous and subbituminous coals. Generation of electricity from lignite is technologically, chemically, physically, and functionally distinct from these other ranks of coal. These distinctions have been recognized by industry, regulators, and by EPA itself. Lignite-fired power plants are technologically and operationally distinct from traditional coal-fired power plants and include different design elements that warranted and resulted in a separate subcategory within the overarching coal category.

Lignite has a lower heat-value than other types of coal, resulting in the need to combust additional fuel in order to meet comparable generation amounts. Further, the physical and chemical composition of lignite also typically requires larger, more energy intensive, control technologies than other coal-fired units. The increased parasitic load of these technologies inherently impacts emissions and performance capabilities of these units.

In addition, lignite EGUs are almost always at mine-mouth power plants that are co-located with the mines that supply their coal. The mine and plant are inextricably linked. Imposing limitations that would require a lignite-fired EGU to comply with the emissions standards of non-lignite units is simply not feasible.

In previous rules, EPA established a subcategory for lignite within the larger coal subcategory, specifically because of the distinct chemical composition of this fuel source, but also because lignite units are "universally constructed 'at or near' a mine containing" lignite with designated and narrowly limited conveyance mechanisms to transport lignite from the mine to the power plant.[1]

The subcategorization of lignite, its unique chemical composition, and the resulting impacts on emission control effectiveness must all be taken into consideration as part of EPA's Proposed MATS Rule.

DISCUSSION

I. Clean Air Act § 112

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of HAP from stationary sources. EPA must first identify categories of sources emitting one or more of the HAP listed in CAA section 112(b) and then promulgate technology-based National Emission Standards for Hazardous Air Pollutants ("NESHAP") for those sources.[2] For major sources, these standards, often referred to as MACT (maximum achievable control technology), must reflect the maximum degree of emission reductions of HAP achievable after considering cost, energy requirements, and non-air quality health and environmental impacts.

For these MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as the MACT floor, and which may not be based on cost considerations. *See* CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The

[1] MATS Rule, 77 Fed. Reg. at 9379. EPA used the term "low rank virgin coal" with a heat-input value of 8,300 Btu/lb, which is almost exclusively lignite.

[2] ''Major sources'' are those that emit, or have the potential to emit, any single HAP at a rate of 10 tons per year (tpy) or more, or 25 tpy or more of any combination of HAP.

MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources).

In the second stage, EPA must conduct two different analyses, which are referred to as the technology review and the residual risk review. Under the technology review, EPA reviews the technology-based standards and may revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years. *See* CAA section 112(d)(6). Under the residual risk review, EPA must evaluate the risk to public health remaining after the application of the technology-based standards and must revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. In conducting the residual risk review, if the EPA determines that the current standards provide an ample margin of safety to protect public health, it is not necessary to revise the MACT standards pursuant to CAA section 112(f).[3]

II. <u>EPA Determined That The MATS Requirements Already Provide An Ample Margin of Safety</u>

In the Proposed Rule, EPA states, "with respect to the standard for fPM (as a surrogate for non-Hg metals), and the standard for Hg from EGUs that burn lignite coal, the EPA proposes to conclude that developments since 2012—and in particular the fact that the majority of sources are vastly outperforming the MACT standards with control technologies that are cheaper and more effective than the EPA forecast while a smaller number of sources' performance lags behind—warrant strengthening these standards." (88 Fed. Reg. 24856).

In other words, EPA believes that because a large number of operators have spent the time and resources necessary to achieve the applicable PM and mercury standards, that these standards cannot be strict enough and should be further tightened. Yet, EPA did not identify any increased risk as part of this risk review and did not make any changes to the 2020 Residual Risk Review, which ultimately determined that the current MACT requirements provided an ample margin of safety.

Specifically, in 2020, EPA's Residual Risk Review determined that:

- both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of acceptability.

[3] The D.C. Circuit has affirmed this approach to implementing CAA section 112(f)(2)(A). *See NRDC* v. *EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008) (''If EPA determines that the existing technology-based standards provide an 'ample margin of safety,' then the Agency is free to readopt those standards during the residual risk rulemaking.''

- The highest chronic noncancer TOSHI and the highest acute noncancer HQ were below 1, indicating a low likelihood of adverse non-cancer effects from inhalation exposures.

- There were also low risks associated with ingestion, with the highest cancer risk being less than 50-in-1 million based on a conservative screening assessment, and the highest noncancer hazard being less than 1 based on a site-specific multi-pathway assessment.

The EPA goes on to say that in 2020, it determined that the MATS requirements provided an ample margin of safety, stating:

"[W]e considered the results of the technology review, risk assessment, and other aspects of our MACT rule review to determine whether there were any cost-effective controls or other measures that would reduce emissions further to provide an ample margin of safety. The risk analysis indicated that the risks from the source category are low for both cancer and noncancer health effects. Thus, we determined in 2020 that the current MATS requirements provided an ample margin of safety to protect public health in accordance with CAA section 112. Based on the results of our environmental risk screening assessment, we also determined in 2020 that more stringent standards were not necessary to prevent an adverse environmental effect."

Finally, in the Proposed Rule, EPA acknowledges that its 2020 review was "a rigorous and robust analytical review using approaches and methodologies that are consistent with those that have been utilized in residual risk analyses and reviews for other industrial sectors"; that there was a "low residual risk from the coal- and oil-fired EGU source category;" and that it is "not proposing any revisions to the 2020 Residual Risk Review." (88 Fed. Reg. 24866)

Despite finding that the existing MATS Rule provided an ample margin of safety in accordance with § 112, that its 2020 review was rigorous and robust, and that it is not proposing any revisions to such review, EPA is still proposing to tighten the MATS requirements. Simply put – EPA has provided no valid reason to further tighten those requirements.

III. EPA Has Not Demonstrated Any Technical Developments Since The Issuance of the Previous MATS Requirements

The 2020 Final Rule did not discover any developments in control technologies, practices, or processes. In 2023 as to fPM, the Proposed Rule concurs. It states that EPA found "no new practices, processes, or control technologies for non-Hg HAP." (88 Fed. Reg. 24868). Yet, EPA identifies fPM "developments" to justify an emissions change based on reporting fPM emissions levels and lower costs than originally assumed. Similarly, for Hg, in 2023, EPA identifies new "developments" for lignite EGUs based on the operator's compliance with the regulations.

The D.C. Circuit has already determined that EPA may not revise a MACT standard in the RTR process unless "developments" happened after the issuance of the original rule.

National Association for Surface Finishing v. EPA, 795 F.3d 1, 11 (2015) (*NASF*). In *NASF*, EPA identified several pre-existing technologies in its analysis (control devices, HEPA filters, tank hoods, fume suppressants) and discussed improvements in the control performance resulting in emissions reductions. The *NASF* court found this was sufficient as a development because EPA discussed the impact of the developments and examined what emissions levels could be achieved. *Id.* The Court held that the record supported the reasonability of this shift. *Id.* at 11-12. The key inquiry was whether the record supports a shift in analysis over time – rather than simply revisiting and revising the original standard without a reason or support.

In the Proposed Rule, EPA provides no new control technologies or methods. For both pollutants, EPA finds "developments" based on control performance (lower emissions data). It appears that because operators have been diligent in reducing emissions and have been able to achieve the standards set by EPA, EPA feels the need to again tighten the applicable standards.

In sum, EPA has found that the current MATS requirements provide an ample margin of safety and has identified no new control technologies or methods. Thus, the Proposed Rule does not comply with the requirements in the Clean Air Act Section § 112.

IV. <u>Even If EPA Had A Sufficient Basis for Updating the MATS Requirements, Its Technical Basis For Doing So Is Based on Faulty Data</u>

For both mercury and particulate matter, EPA's proposed reductions to the applicable emission limits are based on data that is simply incorrect or fails to acknowledge how emission control technologies actually work.

A. <u>EPA Relies on Incorrect Data Regarding San Miguel's Mercury Inlet</u>

The Proposed Rule provides that the proposed reduction in the mercury limit for lignite-fired units is based on information provided to the Energy Information Administration and by using the information collection authority provided under CAA section 114. Table 8 shows the Hg Inlet level which reflects the **<u>maximum</u>** mercury content of the range of feedstock coals that the EPA assumes is available to each of the plants in the Integrated Planning Model ("IPM"). In Table 8 of the Proposed Rule, EPA states that the mercury inlet concentration at San Miguel is 14.65 lb/TBtu. This data is simply wrong.

San Miguel has provided information to EPA in response to a 114 Information Request, which shows the average mercury inlet concentration to be 34 lb/TBtu. Furthermore, this is not a snapshot or cherry-picked data – this is the average concentration going back to 2011 – more than a decade's worth of data.

Table 1: Historical Mercury Inlet Concentrations Since 2011 and Required Removal Rates

Calculated Mercury Inlet and Mercury Capture Rates at Full Load Using Lignite Monthly Composite Data from 2011 - Present		
	4.0 lb/Tbtu target	1.2 lb/Tbtu target
Minimum Mercury Inlet, lb/Tbtu	Capture Percentage Required to Reach Target with Minimum Mercury Inlet Concentration	Capture Percentage Required to Reach Target with Minimum Mercury Inlet Concentration
22.8	82.4%	94.7%
Average Mercury Inlet, lb/Tbtu	Capture Percentage Required to Reach Target with Average Mercury Inlet Concentration	Capture Percentage Required to Reach Target with Average Mercury Inlet Concentration
34.0	87.8%	96.3%
Maximum Mercury Inlet, lb/Tbtu	Capture Percentage Required to Reach Target with Maximum Mercury Inlet Concentration	Capture Percentage Required to Reach Target with Maximum Mercury Inlet Concentration
69.4	94.2%	98.3%

Despite having this information, EPA concluded that the mercury inlet concentration at San Miguel was 14.65 lb/TBtu – less than half of the average at San Miguel.

EPA's incorrect data also fails to recognize the highly variable mercury content of lignite. The highest mercury inlet concentration at San Miguel since 2011 was as high as 69 lb/TBtu. On the other hand, the lowest recorded mercury inlet concentration at San Miguel in over a decade was 23 lb/TBtu, still significantly higher than the numbers the EPA uses to justify its proposed mercury limit.

San Miguel has recently averaged around 25-29 lb/TBtu inlet mercury – double the assumed **maximum** rate that the EPA used in their analysis presented in Table 8. Since 2011 they have averaged around 34 lb/TBtu inlet mercury. With the variable inlet mercury content in their fuel, meeting the current 4.0 lb/TBtu emission standard requires constant focus. Maintaining compliance with an emission limit that is 70% lower than the current standard is not feasible.

The full range of actual inlet conditions indicates San Miguel would need around a 94% mercury removal rate to achieve the current 4.0 lb/TBtu emission standard and would need around a 98% mercury removal rate to achieve the proposed 1.2 lb/TBtu emission standard. This level of removal is well above the performance assumed by the EPA to achieve compliance. Furthermore, San Miguel would need to target a lower emission rate like a 1.0 lb/TBtu limit to achieve compliance over the entire 30-day rolling average period.

B. EPA Incorrectly Assumes That Emission Control Efficiency for Powder River Basin Coal Is Equivalent To That For Lignite

EPA correctly notes that the natural alkalinity of subbituminous and lignite fly ash "makes control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs more challenging than the control of Hg from bituminous coal-fired EGUs." (88 Fed Reg. 24880).

The EPA goes on to note that "EGUs firing subbituminous coals have been able to meet the 1.2 lb/TBtu emission standard…it is difficult to justify why those [lignite] units should not meet a similar level of Hg control as that of the EGUs firing Powder River Basin ("PRB") subbituminous coal given the similarities between the two fuels—especially the similarities in Hg content, halogen content, and alkalinity."

Surprisingly, EPA appears to have ignored the findings in a 2013 technical report prepared by Sargent & Lundy that was prepared for EPA to analyze mercury controls (the "S&L Report"). The report directly contradicts EPA's supposition that lignite-fired units should be able to meet the same standard as PRB subbituminous units.[4] S&L Report describes in detail how activated carbon injection is rendered significantly less effective when the flue gas contains SO_3, stating:

> Some flue gas constituents, especially SO_3, reduce the mercury removal effectiveness of both activated carbon and non-carbon sorbents. With flue gas SO_3 concentrations greater than 5 - 7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, the capacity of activated carbon can be cut by as much as one-half with an SO_3 increase from just 5 ppmv to 10 ppmv.

The higher sulfur content of lignite equates to greater production rates of SO_3. Texas lignite units often have high flue gas SO_3 concentrations and could be considered medium- to high-sulfur coals based on pounds of SO_2 produced per million Btu of heat input.[5] Gulf Coast lignite generally features higher sulfur content - by a factor of two or more. Notably, Texas lignite is disadvantaged as the alkalinity to sulfur ratio is half that of PRB.

As to San Miguel, since 2017, the sulfur percentage of the lignite fuel ranges from a minimum of 1.31% to a maximum of 3.42%. The lignite fuel used at San Miguel during that

[4] *IPM Model: Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology,* Sargent & Lundy, Project 12847-002 (March 2013).

[5] SO_3 Mitigation Guide and Cost Estimating Workbook

time period had an average of 2.48% sulfur content. Based on a fuel analysis conducted in 2014, San Miguel has an average sulfur content of 9.6 lb/SO_2 per million Btu.

EIA data shows that even excluding the outlier values of Hg (approximating 50 lbs/TBtu), lignite presents significantly greater variability in Hg and sulfur than PRB.

Consequently, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows measurable levels of SO_3 in the lignite-generated flue gas. EPA does not recognize this distinguishing difference.

When EPA sets its proposed emission limits for lignite-fired EGUs, EPA simply assumed such units would be fully capable of meeting the same standard as PRB-fired units. In so doing, EPA has not only failed to recognize the difference in sulfur content of various coal veins, but has also failed to observe the significant impact of certain flue gas constituents on the effectiveness of activated carbon injection as a means to control mercury emissions.

C. Proposed fPM Limits Are Not Achievable

Particulate at San Miguel is captured and removed from the flue gas path primarily by the existing ESPs. The wet flue gas desulfurization ("WFGD") system downstream of the electrostatic precipitators ("ESPs") will also capture some of the particulate that makes it through the ESPs. The effectiveness of the existing ESPs and WFGD system to control PM emissions is demonstrated by the data in Table 2. San Miguel works extremely hard to maintain compliance with this standard. Compliance with the proposed fPM emission limit of 0.01 lb/MMBtu will be marginal under even the best operating scenarios.

Table 2: Summary of Filterable Particulate Matter (fPM) Quarterly Emissions Since 2016

	Measured fPM 0.03 lb/MMBtu current limit		Margin with Proposed Limit (lb/MMBtu)	Percent Margin (%)
min	0.00600		0.00400	40.0%
5th percentile	0.00614		0.00386	38.6%
average	0.03266		-0.02266	-226.6%
95th percentile	0.16411		-0.15411	-1541.1%
max	0.23300		-0.22300	-2230.0%

To achieve compliance with the proposed 0.01 lb/MMBtu limit, San Miguel may consider several options including: 1) ESP upgrades, 2) full fabric filter downstream, 3) reduced size fabric filter downstream, and 4) an ESP to fabric filter conversion.

D. No Support for PM CEMS Requirement

EPA appears to support the requirement to use PM CEMS by stating: (1) PM CEMS are required for new EGUs and (2) the revised emission standards for existing EGUs and new EGUs are pretty much the same.

The fact that PM CEMS are required for new coal-fired EGUs is a weak argument. PM CEMS are not and have never been demonstrated on new EGUs. The EPA is well aware of this, explaining that it was not revising the NSPS for newly constructed coal-fired EGUs because no such units were being built.[6] Supporting the proposed use of PM CEMS for existing EGUs with a theoretical requirement for new EGUs that have not been built and will never be built is not a viable argument.

E. EPA Has Severely Underestimated The Costs Of The Proposed Rule

EPA estimates that the total cost of the Proposed Rule is $230M - $330M, with annual compliance costs of $33M to $38M. The cost estimates provided by EPA severely underestimate the actual costs. San Miguel has conducted a thorough review of the capital and O&M costs that it will be required to take in order to comply with the Proposed Rule. The data provided below in Table 3 demonstrates just how far off base EPA's numbers really are.

Table 3: Summary of Capital and O&M Costs[7]

High Estimate	Capital	O&M	NPV	Total Levelized Cost
Option	**(2024$)**	**(2024$)**	**(2024$)**	**$/yr (2024$)**
New Mercury Controls	$10,800,000	$12,745,000	$213,493,000	$21,126,000
New Baghouse	$160,000,000	$4,220,000	$209,671,000	$20,747,000
New Particulate CEMS	$1,950,000	$25,000	$2,133,000	$211,000

Low Estimate	Capital	O&M	NPV	Total Levelized Cost
Option	**(2024$)**	**(2024$)**	**(2024$)**	**$/yr (2024$)**
New Mercury Controls	$8,100,000	$10,631,000	$177,277,000	$17,542,000
New Baghouse	$130,000,000	$3,430,000	$170,378,000	$16,859,000
New Particulate CEMS	$1,450,000	$25,000	$1,688,000	$167,000

1. Mercury Control

The basis for the cost estimate includes a new liquid chemical feed system and new dry sorbent storage and injection system. The liquid chemical feed system includes a bulk 10,000-

[6] 88 Fed. Reg. 33,245 (May 23, 2023).

[7] This assumes a project start date of 2024 and plant retirement date of 2040. Inflation rate of 3 percent and discount rate of 6 percent were used

gallon SF-20 liquid storage tank to provide a 14-day supply of chemical plus 2 x 100% capacity liquid chemical feed pumps assembled on a common chemical feed skid inside a shop-fabricated enclosure.

The dry chemical feed system includes a new 500-ton storage silo plus 2 x 100% capacity blowers, piping, instrumentation, and valves necessary to inject the sorbent material into the flue gas duct. We have estimated the installation cost for the new mercury control equipment to be in the range of $8.1 M to $10.8 M.

Annual operating cost calculations were completed on the SF-20 and SB-31 injection rates needed to achieve 1.2 lb Hg/TBtu based on the historical average mercury concentration of 34 lb/TBtu. An SF-20 injection rate of 30 gal/hour was assumed along with an SB-31 injection rate of 1,200 lb/h per vendor recommendations. Annual emissions for the last three years were obtained from the EPA – Clean Air Markets Program Data website to find the average capacity factor of approximately 81% over the past three years. SB-31 cost was assumed to be $1.15/lb which was the value used in the proposed MATS rule. The annual operating and maintenance cost of the mercury control system is estimated at approximately $10,631,000 - $12,745,000, or about **$10,000/lb Hg removed**.

2. fPM Control

To achieve compliance with the proposed 0.01 lb/MMBtu limit, San Miguel may consider several options including: 1) ESP upgrades, 2) full fabric filter downstream, 3) reduced size fabric filter downstream, and 4) an ESP to fabric filter conversion.

Capital costs for the ESP upgrades are projected in the $20 M range. However, there is no way to know with any certainty if the ESP upgrades will be able to achieve compliance with the proposed fPM limit of 0.01 lb/MMBtu on a continuous basis. As such, an ESP upgrade is considered technically not feasible.

A full-size baghouse installation in the $130 M to $160 M range. The reduced size baghouse would fall around 10 to 20 percent lower in total installed cost ($98 M - $145 M). The ESP to fabric filter conversion would fall around 20 to 40 percent lower cost ($80 M – $130 M) than the full-size fabric filter and would require a 3 to 4 month unit outage.

CONCLUSIONS

The results of the 2020 RTR showed that emissions of HAP from coal- and oil-fired power plants have been reduced such that residual risk is at an acceptable level. EPA has carefully reviewed the 2020 assessment of residual risk and has decided not to propose any changes to the risk analysis in this action. EPA did not find any errors in the 2020 residual risk review, and has determined that the risk review was conducted using approaches and methodologies that are consistent with prior residual risk analyses and reviews for other industrial sectors. Without any additional risk identified, EPA still proposes stricter rules that will cost hundreds of millions of dollars.

Furthermore, EPA has not identified any technical advancements that would merit an update to the MATS Rule. In an odd twist, simply because operators have made the effort to comply with the MATS Rule, EPA has decided that it should be more stringent.

Not only that – EPA's technical basis for the Proposed Rule is based on faulty mercury data, disregard for demonstrated emission control results, and a severe underestimate of the capital and O&M costs that operators will be required to make in order to comply with the Proposed Rule.

Thank you for your consideration of these comments.

Respectfully,

Craig Courter
General Manager/Chief Executive Officer
San Miguel Electric Cooperative, Inc.

Exhibit 3

ROBERT MCLENNAN
DECLARATION OF HARM IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

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

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

3. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's (EPA) National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review (the Final Rule or the MATS RTR).

4. Minnkota is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. Minnkota provides wholesale electric energy to 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota. Minnkota also serves as the operating agent for the Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN.

5. Electricity generated by Minnkota is distributed through the Midcontinent Independent System Operator (MISO) regional transmission organization (RTO). MISO "operates the transmission system and centrally dispatched market" in fifteen states ranging from Canada down to the Gulf

Coast. Across those states, it serves more than 42 million customers.[1] Minnkota and its system partners (Northern Municipal Power Agency and Square Butte Cooperative) have the capability of generating 1,425 MWs, which may be provided to MISO for scheduling and reliability purposes. Over half of the electricity generated by Minnkota is dispatchable power from coal sources, meaning it is available on demand, unlike power from wind and solar resources, which do not have on-demand capabilities. Dispatchable power is critical for MISO because MISO has small reserve margins, which is the amount of power needed to ensure demand is met and avoid failure of the grid.

6. Minnkota is a member of the Lignite Energy Council (LEC). LEC represents the regional lignite industry in North Dakota, an $18 billion industry critical to the economy of the Upper Midwest and the reliability of its electrical grid. The primary objective of LEC is to maintain a viable lignite coal industry and enhance development of the region's lignite

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

resources. Members of LEC include mining companies, utilities that use lignite to generate electricity, synthetic natural gas and other valuable byproducts, and businesses that provide goods and services to the lignite industry. LEC has advocated for its members since 1974 to protect, maintain, and enhance development of our region's abundant lignite resources. LEC is committed to environmental stewardship and understands the importance of protecting North Dakota's natural beauty.

7. Minnkota is a member of the National Rural Electric Cooperative Association (NRECA). NRECA represents the interests of rural electric cooperatives across the country.

8. Minnkota is a member of America's Power (AP). AP is a national trade organization that advocates at the federal and state levels on behalf of the U.S. coal fleet and its supply chain.

9. North Dakota contains the world's largest known deposit of lignite and is the fifth-largest coal producing state, accounting for 5% of total U.S. coal production. Most of that lignite is utilized at mine-mouth power generation facilities, which are coal-fired power plants built near a

coal mine that use coal from that mine as fuel. As a result of this plentiful natural resource, coal provides the majority of the electric power generated and consumed in North Dakota.

10. The MATS RTR threatens the viability of North Dakota's lignite-powered plants. It also threatens the reliability of the entire grid across the region, places burdens on the power sector as a whole, and causes harm to industries dependent on a reliable electric grid.

MILTON R. YOUNG STATION

11. Minnkota is the operator and a partial owner of the Milton R. Young Station (the Young Station or MRY), a two-unit (the Units or MRY 1 and MRY 2), cyclone lignite coal-fired power plant located near the town of Center, North Dakota.

12. MRY 1 and 2 are well-controlled electric generating units (EGUs), which provide energy to the MISO system. MRY Units 1 and 2 have substantially reduced NOx and SO2 emissions, which have been documented in the context of the Regional Haze program. MRY 1 has reduced SO_2 emissions by 96% since 2002, and MRY 2 has reduced SO_2 by

75% since 2002. Both Units have reduced NOx emissions approximately 60% since 2002.

13. MRY 1 is a cyclone lignite-fired unit with a 235 MW nominal net rating. The Unit controls NOx with advanced separated over-fire air (ASOFA) and selective non-catalytic reduction (SNCR). A wet scrubber controls SO_2. An electrostatic precipitator (ESP) controls particulate matter (PM).

14. MRY Unit 2 is also a cyclone lignite-fired unit, with a larger capacity (440 MW nominal net rating). It also is equipped with a SNCR, wet scrubber, and an ESP.

15. The MRY Units have different configurations. Although Minnkota uses the same control devices for the Units, operation and emissions output differs based on a number of factors. The Units vary in capacity and control device design. MRY 2 has a different ductwork configuration between the air heater and the electrostatic precipitator than MRY 1. MRY 1 has shorter ductwork and a smaller outlet for measurement of mercury emissions. The ductwork configuration affects the amount of

residence time for the flue gas to be exposed to the injection of powder activated carbon (PAC), also known as activated carbon injection (ACI) in the Final Rule.

16. Minnkota uses the same mercury control strategies for both Units. Minnkota currently uses a fuel additive system to apply a Potassium Iodide fuel additive sorbent known as M-Prove procured from ARQ (formerly ADA). Minnkota injects non-halogenated PAC post-combustion. The fuel additive system was designed to meet the original 2012 MATS limitation for lignite units of 4.0 lb/TBtu, with a margin for compliance due to the variability of lignite coals.

17. MRY 1 and 2 at the Young Station combust lignite coal. The Young Station's lignite supply comes exclusively from BNI Coal Inc. (BNI), which is in close proximity to the plant. The lignite supplied by BNI is run-of-mine (ROM) coal that contains impurities and does not conform to a single mineral content or heat value specification. For this reason, the ROM supply currently varies in mercury content from 4.9 lb/TBtu to 18.6 lb/TBtu, based on recent mercury content testing. *See* Sargent & Lundy, "Mercury

Testing Results for the MATS Residual Risk and Technology Review," at Table 2-5 (May 22, 2024) [hereinafter Mercury Testing 2024 Report], **Attachment A**. The broad range of variability is projected to continue into the future. *See id.* at Table 2-4.

MATS RTR RULE REVISIONS

18. The MATS RTR eliminates the low rank coal subcategory for lignite-powered facilities and changes the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the New Mercury Limitation). EPA assumes this limit can be met using brominated ACI to achieve greater than 90% mercury removal by lignite-burning units. 89 Fed. Reg. 38508, 38547 (May 7, 2024).

19. The MATS RTR decreases the limit for filterable particulate matter (fPM) to 0.010 lbs/MMBtu (the New fPM Limitation).

20. Compliance with the New Mercury and fPM Limitations is required on or before three years after the effective date of the Final Rule.

21. The MATS RTR provides that Continuous Emission Monitoring Systems (CEMS) are the only method to demonstrate compliance with the fPM limit.

LIGNITE COMBUSTION

22. Lignite varies in composition and the distribution of mercury within individual coal samples is not uniform, unlike other types of coals. The amount of mercury within one seam of coal can vary drastically, not to mention mercury content fluctuations between seams at the same mine.[2] Minnkota's units see this large degree of variability within a 24-hour operating period. *See* **Attachment A**, at Tables 2-4, 2-5.

23. An important difference between mine-mouth coal plants and typical coal-fired power plants is the control over fuel composition. Non-mine-mouth facilities purchase coal of a specified quality to be delivered to the facility. Unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, many North

[2] LEC Comments filed June 23, 2024, https://downloads.regulations.gov/EPA-HQ-OAR-2018-0794-5957/attachment_1.pdf

Dakota lignite units are located at mine-mouth facilities without access to other coal types. MRY does not have access to alternate coal supplies. It has no rail spur or barge access to transport the coal to the facility. Therefore, MRY depends entirely on the fuel extracted from the neighboring BNI mine, and without incurring substantial economic cost and significant waste of resources, MRY has no means to control coal quality.

24. When high mercury batches of coal are combusted, the original 2012 MATS mercury emission limitation provided lignite power plants enough margin in their percentage of mercury removal to account for higher mercury emissions due to the mercury content in the coal. 77 Fed. Reg. 9304, 9490 (Feb. 16, 2012).

25. It is well-known and consistent with Minnkota's experience that lignite deposits vary significantly in quality, including fuel combustion performance and mineral content. Mercury content in the lignite varies because different seams within the mine yield lignite with diverse attributes (including mercury) on a day-to-day basis. Minnkota currently

maintains continuous emission controls to accommodate for the changing lignite quality to assure compliance with existing MATS mercury limitations. The variability of the lignite results in a much broader design range of controls and the equipment operation must account for the maximum mercury ROM and in turn must have a greater performance design standard for removal percentage removal. A compliance margin in the performance design standard for percentage removal is critical to allow for controls to adjust in response to changing lignite content, assuring continuous compliance with the MATS RTR Rule. *See* **Attachment A**, at Table 2-4.

ELIMINATION OF THE MERCURY SUBCATEGORY FOR LIGNITE CAUSES IMMEDIATE AND IRREPARABLE HARM TO THE NORTH DAKOTA LIGNITE INDUSTRY AND TO MINNKOTA

26. EPA established the lignite subcategory for mercury because lignite units have different characteristics than units designed to combust bituminous and subbituminous coals. 77 Fed. Reg. at 9378. Lignite has a higher mercury content in many instances and presents greater variability than other coals. *See* E.J. Cichanowicz, "Technical Comments on MATS

RTR," EPA-HQ-OAR-2018-0794-5956, at Section 6.3.1 EIA Hg-Sulfur Relationship (June 19, 2024) [hereinafter Cichanowicz Technical Report], **Attachment B**. The higher sulfur content found in lignite fuels inhibits the ability of injected sorbents to reduce mercury emissions at lignite plants. The mercury content also results in higher levels of SO_3 formed, which significantly limits the mercury emission reduction potential of emission controls at lignite plants. *Id.*

27. Minnkota has used the same technology (combination of sorbent injection plus a chemical additive (oxidizing agent)) as its primary mercury control strategy since the MATS rule came into effect. While there are many variations of PAC on the market, in Minnkota's experience with these products, no PAC product has been identified as more successful than the others at MRY. Therefore, Minnkota has continued to use activated carbon injection as its primary mercury control system. Minnkota is not aware of any new developments in practices, processes, and control technologies in mercury control since the original MATS rule's technology evaluation.

28. Minnkota is unaware of any verified testing or evidence that demonstrates that lignite units can meet the New Mercury Limitation of 1.2 lb/TBtu at full load. EPA finds that by using brominated activated carbon, without regard for equipment performance design, "greater than 90 percent Hg control can be achieved at lignite-fired units," 89 Fed. Reg. at 38547, and cites for support a beyond-the-floor memorandum from the 2012 MATS rule, Kevin Culligan, SPPD/OAQPS to EPA-HQ-OAR-2009-0234, "Emission Reduction Costs for Beyond-the-floor Mercury Rate for Existing Units Designed to Burn Low Rank Virgin Coal" (Dec. 16, 2011) [hereinafter Beyond-the-Floor Memorandum], **Attachment C.** EPA concludes that "units could meet the final, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule." 89 Fed. Reg. at 38547. To support this removal rate, the Beyond-the-Floor Memorandum cites a technical publication: Sjostrom, "Activated carbon injection for mercury control: Overview," Fuel Vol. 89, Issue 6, at 1320-22 (June 2010) [hereinafter ACI Fuel 2010 Article], **Attachment D**.

The ACI Fuel 2010 Article presents a chart that compiles mercury removal test results from Department of Energy (DOE) mercury control systems. The ACI Fuel 2010 Article scatterplot presents a variety of results under different conditions and equipment configurations. The ACI Fuel 2010 Article dataset contains only one lignite datapoint, which is a unit equipped with a fabric filter. Fabric filters aid in mercury removal because of increasing resonance time and temperature differential. The raw testing data from the ACI Fuel 2010 Article is not available in the docket. Given that the dataset (1) uses a single lignite data point (containing Fabric Filter controls), (2) fails to include the backup testing data, and (3) lacks data from ESP-equipped units like the MRY Units, the scatterplot in the ACI Fuel 2010 Article does not support the conclusion that a emissions standard based on 90% mercury removal can be achieved across the lignite industry, particularly with respect to lignite-fired units that are not equipped with a fabric filter.

29. Concluding that mercury removal over 90% is possible and equates to meeting the New Mercury Limitation, EPA calculates the removal

percentages for various lignite units across the country. EPA reports that lignite plants would need to remove up to 95% of mercury in the flue gas to meet the new limit based on 2022 data. 89 Fed. Reg. at 38547.

30. After the release of the proposed MATS RTR, Minnkota performed testing to evaluate the capability of its current mercury reduction system at MRY 1 and to examine the feasibility of EPA's mercury removal assumptions as applied to MRY 1. *See* **Attachment A**. Minnkota used its existing mercury control system to apply PAC and M-Prove sorbent, both of which MRY uses routinely for mercury control. Minnkota added as much PAC and Potassium Iodide sorbent as the MRY conveyors, injection lances, and associated components would allow, based on their maximum performance design capabilities and consistent with good engineering practices. As described in more detail in the Mercury Testing 2024 Report (**Attachment A)** the test results showed:

MRY Unit	Average Hourly Mercury Emissions Value Achieved at Full Load (Sorbent Trap Data) 18 ppm MProve and Non-Brominated PAC
Unit 1	2.17
Unit 2	1.61

31. The Final Rule solely relies on the conclusion that brominated PAC improves mercury removal. 89 Fed. Reg. at 38547 (citing the Beyond-the-Floor Memorandum). Consequently, MRY purchased brominated PAC for the purpose of determining if that product would achieve improved mercury removal as compared to non-brominated PAC. Minnkota selected MRY 1 for this trial because its mercury emissions baseline rate was higher than MRY 2 in the results identified above. As shown below, the MRY 1 average mercury emissions rate was higher when injecting brominated PAC as compared with non-brominated PAC.

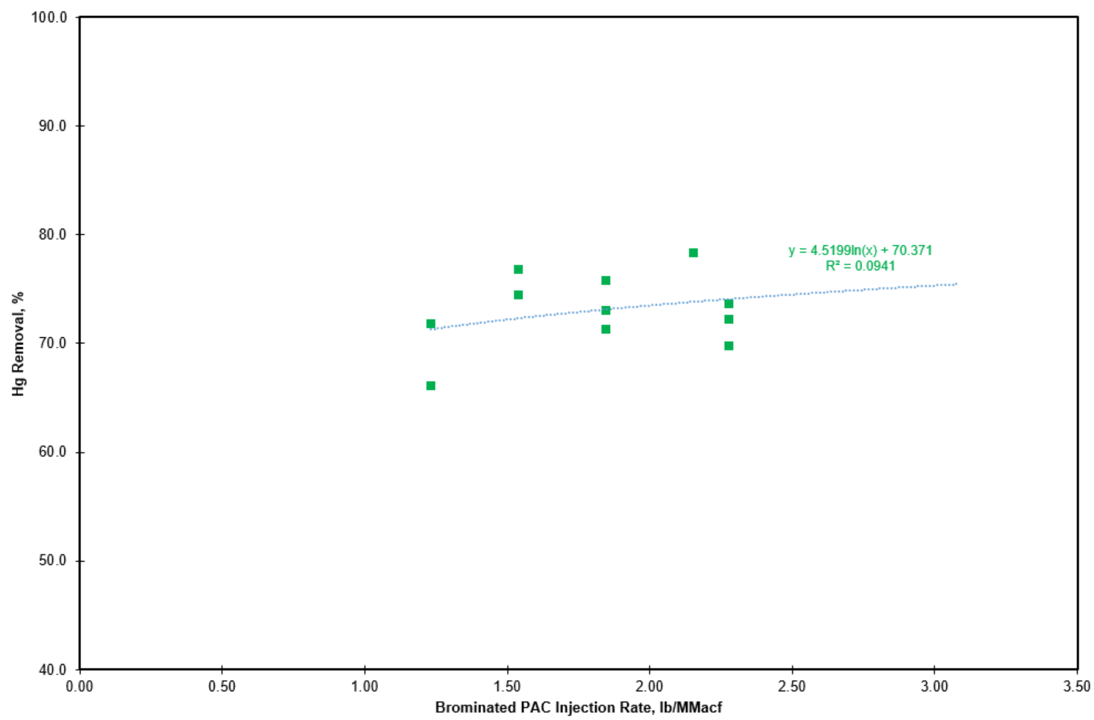
MRY Unit	Average Hourly Hg Emissions Value Achieved at Full Load (Sorbent Trap) Brominated PAC	Average Hourly Hg Emissions Value Achieved at Full Load (Sorbent Trap) Non-Brominated PAC
Unit 1	2.57	2.17

32. With existing equipment, the recent testing results demonstrate that MRY is unable to achieve the New Mercury Limitation on an hourly basis at full load. Further, Minnkota has no information or data supporting the conclusion that MRY 1 or MRY 2 could achieve the New Mercury Limitation on a 30-day rolling basis while operating at full load. The short-term testing data suggest that even a longer-term averaging period would not result in compliance.

33. In fact, Minnkota plotted the recent test results to project the removal rate at a brominated PAC injection rate of 3.0 lb/MMacf, which is a higher injection rate than the existing MRY equipment can achieve, but is consistent with EPA's achievability conclusion in the Beyond-the-Floor Memorandum and Final Rule. The trend line shows an estimated maximum mercury removal rate of less than 80%. The plotted trend line, based on the test values, is far below EPA's conclusion (consistent with the ACI Fuel 2010 Article) that injection of brominated PAC at the rate of 3.0 lb/MMacf will result in a 90% removal rate. Rather, the trend line levels off, demonstrating that increasing the amount of brominated PAC injected

into MRY Unit 1 is not an adequate control strategy to achieve the New Mercury Limitation and that EPA ignored and erroneously omitted limitations of ACI in its achievability conclusion. **Attachment A**, at Figure 2-1. The scatterplot from the Report is presented below.

Figure 2-1 — MRY Unit 1 Existing System Mercury Removal Performance Capabilities using Brominated PAC



34. Mercury testing and analysis of data at MRY confirms and supports Minnkota's belief that numerous variables affect its mercury emissions rate. Specifically, Minnkota observed mercury emissions rate fluctuations based on unit load, mercury content in lignite, and normal variability in unit operation and control equipment function. Some hourly

mercury emissions increases were not directly traceable to a cause, even upon data analysis.

35. One of Minnkota's conclusions, based on recent testing experience, is that known and unknown variables cause mercury emissions fluctuation, such that a standard for mercury must include a minimum compliance margin of 25%.

36. Minnkota is irreparably harmed by the final MATS RTR because MRY's existing mercury controls cannot achieve the New Mercury Limitation of 1.2 lb/TBtu on an hourly or sustained basis at full load. In fact, the MRY testing data predicts that increased injection of brominated PAC beyond the capabilities of the existing mercury control system will not achieve the New Mercury Limitation due to the leveling off of mercury removal at less than an 80% removal rate.

37. The Final Rule places Minnkota in an urgent and untenable position, given the Rule's impending compliance date. Noncompliance with the Clean Air Act is not an option. Therefore, prior to making a shutdown decision regarding critical assets, Minnkota would determine

what mercury emission rate the MRY units can achieve. That would require significant additional investment in testing that, along with existing testing costs, will exceed $600,000.00.

38. To achieve lower mercury emissions, MRY must install and operate advanced pollution control equipment to replace its existing equipment, such as an ACI system with a higher injection rate. Even though the New Mercury Limitation is not shown to be feasible, Minnkota must complete this installation project to improve the emission rate and avoid the only other option of derating the units for compliance. The installation costs and ongoing operation expenses are significant. Specifically, these technologies will require an estimated minimum of $5,000,000.00 capital expenditure upfront, as well as increased labor costs for installation, operation, and maintenance of the technology, and equipment and associated training, and will result in increased operating costs over the long term. This expenditure must take place expeditiously and certainly before the resolution of this case.

39. Without the ability to meet the New Mercury Limitation, the Final Rule provides no other option but to force Minnkota to ultimately shut down MRY Unit 1 and Unit 2. Shutting down MRY substantially harms Minnkota by entirely eliminating its ability to generate dispatchable electricity for its cooperative members and end users.

40. EPA failed to take into consideration the actual costs of compliance and had a significantly flawed calculation. *See* **Attachment A**, at Section 3 EPA Cost Validity.

41. Further, EPA underestimates the cost of the Final Rule to Minnkota by using incorrect fuel additive costs for MRY 1 and for MRY 2. EPA's underestimate results in $487,747 and $1,347,383 that should have been included in the cost analysis for MRY Units 1 and 2, respectively.

42. The magnitude of EPA's underestimation of cost is apparent when actual compliance costs are used to calculate cost effectiveness. Compared to EPA's hypothetical 800 MW unit, the cost for just one 250 MW lignite unit is nearly 80% EPA's estimate—and this fails to include equipment upgrades necessary to achieve an injection rate unproven to

meet a 90% removal rate on lignite. Note the table does not include or account for any costs associated with MRY 1 mercury system upgrades.

Example MRY Unit 2 Cost Underestimations Summary Table 3-1

Parameter	EPA Example Hypothetical 800 MW	EPA Assumed MRY U2 Costs 447 MW	Est. Actual MRY U2 Costs 447 MW
Current Hg Compliance (4.0 lb/TBtu) Cost [1]	$2.6 M	$0.3 M	$1.9 M
Current Hg Removed	1,295 lb	77 lb	149 lb
Current C/E ($ per lb Hg Removed)	2,004	3,845	12,754
Hg Control System Annualized Capital Cost	Not included	Not included	$472k [2]
BPAC Cost @ 5 lb/MMacf	$7.5 M	$0.6 M	$1.3 M [3]
M-Prove Cost	Not included	$0.2 M	$1.6 M [4]
Future Hg Compliance (@ 5 lb/MMacf) Cost	$7.5 M	$0.8 M	$3.4 M
Future Hg Removed (EPA Assumed @ 1.2 lb/TBtu)	1,447 lb [5]	110 lb	216 lb
Future C/E ($ per lb Hg Removed)	5,083	7,040	15,678
Incremental C/E ($ per lb Hg Removed)	28,176	14,360	22,217

Note 1 – EPA example only based on sorbent. EPA assumed current compliance cost includes sorbent and chemical fuel additive. Est. actual cost based on 2023 MRY Unit 2 usage rate & pricing for both sorbent and chemical additive.
Note 2 – Cost of $5.0 million dollars from S&L project database was annualized using a capital recovery factor calculated based on annual interest rate of 7% (pre-tax marginal rate of return on private investment, EPA Cost Manual Section 5) and 20 year evaluation period (EPA Cost Manual Section 6).
Note 3 – Cost based on EPA assumed rate but using 2023 MRY BPAC pricing.
Note 4 – Cost based on 2023 MRY Unit 2 usage rate & pricing instead of assuming same as sorbent costs.
Note 5 – Based on calculated value for EPA example inlet Hg of 1,542 lbs (current Hg coal content) – 95 lbs (future emitted amount). However, the EPA example identifies 1,468 lb for the incremental cost effectiveness calculation.

43. Costs to comply with the New Mercury Limitation are exorbitant and damage Minnkota. Many costs may be passed along to its member cooperatives and end users who are harmed via higher electricity

prices. The capital and operational costs to Minnkota, its member cooperatives, and end users cannot be recouped.

44. At a minimum, compliance with the new standard for mercury is estimated to cost $22,217 per pound of incremental emission removed for Unit 2. The significant cost of reducing mercury emissions is overly burdensome for Minnkota as a small entity and as a not-for-profit electric cooperative.

45. Minnkota's harm due to the New Mercury Limitation is immediate. Minnkota must immediately begin mercury testing to determine maximum mercury removal rates and capabilities.

46. The MATS RTR sets a mercury limitation for lignite units without any technical basis or data demonstrating its achievability. In summary, the New Mercury Limitation is defective due to the following flawed assumptions:

a. EPA assumes that greater than 90% mercury control can be achieved at lignite-fired units at a < 2.0 lb/MACF injection rate for units with installed fabric filter and using brominated PAC and greater than 90% mercury control can be achieved at lignite-fired units at < 3.0 lb/MACF injection rate for units with installed ESPs and using brominated PAC. Yet, MRY's testing data demonstrates that EPA's assumptions that greater than 90% mercury control can be achieved is in error. EPA's Beyond-the-Floor Memorandum and its supporting data also demonstrates that EPA's achievability conclusions around application of ACI are clearly erroneous.

b. EPA finds that no lignite units will need to achieve a removal rate higher than 95% mercury control to meet the New Mercury Limitation of 1.2 lb/TBtu, based on EPA's unit-by-unit calculations, and finds MRY would need 87% removal in the Final Rule. Yet, Minnkota's calculations for MRY show that greater than 90% removal would be required when combusting high mercury content lignite based on test results at the mercury inlet.

47. Minnkota is harmed by having to comply with a New Mercury Limitation that is not achievable and is based on flawed and unsupported technical conclusions.

THE NEW fPM LIMITATION WILL CAUSE IMMEDIATE AND IRREPARABLE HARM TO THE NORTH DAKOTA UTILITIES AND TO MINNKOTA

48. EPA's new fPM limit of 0.010 lb/MMBtu will require either the installation of a baghouse (fabric filter technology) or complete retrofit of electrostatic precipitators at MRY. *See* Sargent & Lundy, "Particulate & Mercury Control Technology Evaluation & Risk Assessment for Proposed MATS Rule Report," EPA-HQ-OAR-2018-0794-5978 (June 2023) [hereinafter MATS 2023 Study], **Attachment E**.

49. ESP improvements may result in fPM reductions. These upgrades would require substantial modifications, including structural support modification, and would represent substantial expenditures in cost per ton removed. **Attachment E**, at Section 2.3.

50. Minnkota's harm is immediate. Minnkota would need to begin constructing an ESP upgrade as soon as possible to have any opportunity to meet the new compliance date for the MATS RTR.

51. For MRY 2, an ESP upgrade may achieve the New fPM Limitation with adequate margin. However, the MATS 2023 Study finds that vendors would have to complete a more detailed qualitative study and baseline testing to determine whether an ESP rebuild can achieve a low enough fPM rate based on ESP inlet and outlet emissions. **Attachment E**, at Section 2.1.6. Otherwise, a baghouse would be required. MRY would need 48 months to convert to baghouse technology. *Id*. at Table 2-2.

52. ESP upgrades take 36 months to complete. There are 26 units in the country that would need ESP upgrades for a new limitation of 0.010 lb/mmBtu. *Id.* Only 4 vendors in the United States can undertake these projects. It is likely that the 36-month estimate will be further protracted due to the dearth of contractors available to perform the work.

53. Costs of compliance with the New fPM Limitation are overly burdensome, for the following reasons.

54. Baghouse installation is extremely costly. It is estimated to cost $282,715 per fPM ton removed. *See* **Attachment B**.

55. ESP retrofits are expensive. NRECA's technical consultant estimates $67,262 per fPM ton removed. *See* **Attachment B**.

56. Electric cooperatives have limited financial resources to undertake projects of this magnitude in general and especially when coincident with other environmental compliance projects.

57. Minnkota is harmed by having to comply with a New fPM Limitation that may not be achievable prior to the compliance deadline, is based on flawed and unsupported technical conclusions, and is very costly.

58. To comply with the MATS RTR, Minnkota is forced to take measures that immediately increase compliance and operational costs. The MATS RTR impacts Minnkota's ability to supply affordable, reliable energy to its customers. Added costs will place upward pressure on rates for rural customers, particularly when combined with the effects of EPA's other recent electric utility sector-focused rules.

THE MATS RTR CREATES GRID RELIABILITY CONCERNS DUE TO EARLY RETIREMENTS OF COAL-FIRED UNITS

59. Lignite coal provides the majority of the electric power generated and consumed in North Dakota. Lignite power plants play a significant role in the regional economy.

60. Thus, this rule, with its reversal of EPA's position on lignite-fired sources, impacts North Dakota more profoundly than other areas of the country. These concentrated impacts affect the ability of the North Dakota utilities to maintain adequate generation resources.

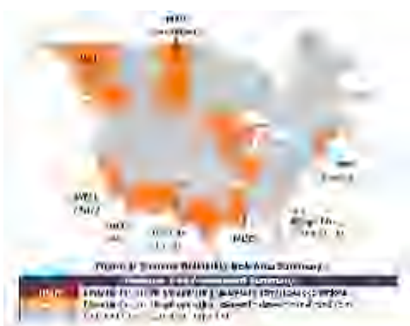
61. Most (if not all) of the lignite plants in North Dakota must make some changes as result of this rule. There will be a marked impact on grid stability and reliability. In addition, increased maintenance needs of new pollution control technology will continue to affect reliability in the longer term.

62. Units will retire due to the inability to meet the New Mercury or fPM Limitations.

63. Existing generation resources are unlikely to be adequate in North Dakota to sustain the grid with multiple unit retirements in a short

time frame. Multiple environmental regulations that EPA promulgated this month directly and profoundly impact generation resources in North Dakota.[3] This Final Rule is part of those cumulative reliability and cost impacts on coal-fired generation.

64. The North American Electric Reliability Corporation (NERC) has predicted continued future shortfalls in North Dakota.[4] The MATS RTR intensifies an already tenuous, overburdened grid in transition.



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[3] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38950 (May 8, 2024); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024).

[4] NERC, 2024 Summer Reliability Assessment (May 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

65. Dramatic repercussions would flow from the loss of North Dakota generation units due to the Final Rule. North Dakota Transmission Authority (NDTA), "Analysis of Proposed EPA MATS Residual Risk and Technology Review and Potential Effects on Grid Reliability in North Dakota" (Apr. 3, 2024) [hereinafter NDTA Analysis], **Attachment F**.

66. The MATS RTR will cause the loss of tax revenue and a decrease in economic activity for the region if units must shut down. Retirements not only economically impact local communities, jobs, and industries, but put more strain on existing resources to provide reliable and affordable energy.

67. The interruption of power delivery from a grid failure would cause damage to public health. North Dakotans rely on electricity to heat their homes during the extreme winter temperatures of the long winter season. Affordable and consistent power allows for medical providers to provide essential services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from grid failures in other areas of the country in winter storms Uri and Elliott show the

documented health impacts and morbidity caused by those events.[5] The MATS RTR places the portion of the grid serving North Dakota in jeopardy of failure and resulting consequences.

68. With respect to MRY, Minnkota would anticipate a loss of jobs. Minnkota employs approximately 200 people in the vicinity of Center, North Dakota. In addition, subcontractors provide services to the plant on a regular basis. The nearby BNI Coal mine would be impacted or possibly close because it sells lignite to MRY. On information and belief, BNI employs approximately 178 persons at the mine. In total, the direct cost to the community from the loss of employment would be staggering. Impacts from the loss of jobs in the area would have a ripple effect on ancillary industries, such as nearby service stations, reduced demand for customer services, and the social and psychological impacts of job loss on the affected individuals and their families. Premature retirement of units

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[5] *See, e.g.*, Hanchey, "Mortality Surveillance During Winter Storm Uri, United States – 2021," Disaster Med Public Health Prep (Dec. 2023), https://pubmed.ncbi.nlm.nih.gov/37974501/; Sharma, "Winter Storm Elliott death toll climbs to 56 as thousands still without power in -40 temperatures," Yahoo News (Dec. 26, 2022), https://www.yahoo.com/news/winter-storm-elliot-power-outages-154557710.html.

results in irreversible harm that economically damages Minnkota and impacts the entire region.

69. EPA failed to account for the costs due to a grid failure in the rulemaking. In its service area, Minnkota would anticipate that grid failures would cause end users to suffer economic damages such as food spoilage, property damage, lost labor productivity, and loss of life. The NDTA Analysis discusses these damages in more detail in Section D (Modeling Results).

SUMMARY OF HARM TO MINNKOTA

70. With respect to the New Mercury Limitation, MRY is unable to meet the new limit with its existing technology at full load. Recent test data suggest that Minnkota will not be able to meet the New Mercury Limitation even at the higher PAC injection rates that EPA assumed to be sufficient to meet the New Mercury Limitation. Further testing and analysis would need to be performed to identify MRY's emission reduction rate. If either no feasible technology exists, or if a technology cannot be installed to meet the compliance deadline, the MRY units will be forced to

ultimately cease operation immediately upon the Final Rule compliance date.

71. With respect to the fPM limitation, Minnkota is unable to meet the New fPM Limitation with its existing technology at full capacity at MRY Unit 2.

72. An ESP rebuild project must take place at a minimum. If further study indicates that an ESP upgrade is not sufficient, Minnkota must install a baghouse. If Minnkota cannot commence these projects – either due to cost or timing – then MRY would be forced to cease operation beginning on the MATS compliance date.

73. Minnkota is immediately harmed because it must expend financial resources to commence testing and project development to lower its fPM and mercury emissions and even have an opportunity to meet the MATS RTR compliance deadline.

74. In summary, the Rule may force MRY off-line due to control infeasibility, cost, or project timing. The Rule would cause this dispatchable,

reliable generating resource to operate differently at a substantial cost and permanent loss to Minnkota.

75. Minnkota's member cooperatives and end users will also be economically impacted. If MRY must prematurely retire, Minnkota would not have time to construct replacement generation prior to the compliance date for the Final Rule in 2027. Minnkota would be faced with increased exposure and reliance on an often volatile and constrained MISO market. Past market pricing demonstrates the extraordinary costs to purchase power from the market. The costs of purchasing power off the MISO market may expose Minnkota's membership to a current cap of $3,500 per MWh. A four-day exposure to the MISO market cap (half of the total days of the market conditions resulting from Winter Storm Uri) would result in a total exposure of $236,888,000 to replace the megawatts that MRY 1 and MRY 2 generate (705 MWns cumulatively), thereby eliminating the entire annual operating revenues of MRY. In fact, these staggering costs have bankrupted a small utility recently (Brazos Electric Power

Cooperative) due to power purchases during Winter Storm Uri from the ERCOT market.

76. The following Tables compile of all of the harms identified herein that Minnkota will suffer due to the Final Rule.

Table A: MRY 1 and 2 Mercury Compliance Costs

Activity	**Cost**	**Notes**
MRY Unit 2 Capital Costs:		
Future mercury testing to determine lowest achievable rate	$600,000	This is a minimum value.
Inlet Hg Monitor	$150,000	To track coal quality
WFGD Additive Dosing System	$750,000	To attempt to reduce mercury emissions further
WFGD Oxidizing Reduction Potential (ORP) Monitoring System	$7,500	For WFGD dosing system feedback
Mercury New PAC Silo and injection equipment capital cost to reach the lowest achievable rate	$5,000,000	Based on industry data from similar projects; This is the total project cost without financing costs.
MRY Unit 2 Operating & Maintenance (O&M) Costs:		
WFGD Additive costs (based on annual operation)	$1,412,000	Based on MRY usage rate and supplier pricing
Mercury control additional PAC costs (based on annual operation)	$1,300,000	Based on EPA hypothetical 5.0 lb/MMacf injection rate for 800 MW unit

Activity	Cost	Notes
Mercury control additional Potassium Iodide costs (based on annual operation)	$1,600,000	Cost based on 2023 MRY Unit 2 usage rate & pricing instead of assuming same as sorbent costs. Cost is $1.4 million more than estimated by EPA.
Incremental Mercury Control O&M cost	$2,412,000	This is the cost in excess of the current O&M costs. This estimate is based on current compliance of approximately $1.9 million.
Capital & O&M Costs:		
Total MRY 2 Costs	**$8,919,500**	Per MW (440MW) = $18,978
MRY 1 Projected Costs	**$4,880,000**	MRY has 235 MW. Based on the cost per MW from itemized costs for MRY 2
Total for MRY 1 and MRY 2	**$13,799,500**	

Table B: MRY 2 fPM Compliance Costs

Activity	Cost	Notes
fPM Feasibility Study	$175,000	Based on roughly budgetary estimates from Southern Environmental , Inc.
Low cost: MRY 2 ESP Rebuild Capital Cost	$36,326,000	Based on S&L's conceptual cost estimates and inputs from Southern Environmental, Inc.

Activity	Cost	Notes
Low cost: MRY 2 ESP Rebuild Incremental O&M Cost	$530,000	Incremental costs accounts for costs incurred above what is currently paid for by station for existing PM compliance (i.e. ESP power consumption, fly ash disposal, etc.)
Low cost: MRY 2 ESP Rebuild Outage Cost	$1,421,000	
High cost: New MRY 2 Baghouse	$242,083,000	Based on S&L's conceptual cost estimating
Low cost: MRY 2 Baghouse Incremental O&M Cost	$4,047,000	Incremental costs accounts for costs incurred above what is currently paid for by station for existing PM compliance (i.e. ESP power consumption, fly ash disposal, etc.)
Low cost: MRY 2 Baghouse Outage Cost	$507,000	
Total fPM Cost Range:	High – $246,812,000 Low – $38,452,000	

Table C: Minnkota's Total MRY Mercury and fPM Compliance Costs

Activity	Cost	Notes
MRY Total Mercury Costs for MRY 1 and MRY 2	$13,799,500	From Table above, O&M based on 1 year
MRY Total fPM Costs for MRY 2	High – $246,812,000 Low – $38,452,000	From Table above, O&M based on 1 year

Activity	Cost	Notes
Total Compliance Cost to MRY	High – $260,611,500 Low – $52,251,500	

77. The compliance cost estimates for MRY to comply with the MATS RTR (assuming its possible for the New Mercury Limit), presented in the above Tables A, B, and C, equate to between 15% (low fPM compliance option) to 60% (high fPM compliance option) of Minnkota's total annual operating revenue. Such expenditures will severely and permanently harm Minnkota's membership.

78. Even if the MATS RTR is overturned, the direct costs to Minnkota, its member cooperatives, and end users cannot be recouped once spent. These damages are permanent.

* * * *

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*   *   *

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

Executed on this 9 day of June, 2024, in Grand Forks, ND.

Robert McLennan

ATTACHMENT A

Minnkota Power Cooperative, Inc.
Milton R. Young Station Units 1 and 2

Mercury Testing Results for the MATS Residual Risk and Technology Review

Rev. 2 *

May 22, 2024

Project No.: A14559.013

S&L Nuclear QA Program Applicable:

☐ Yes

☒ No

55 East Monroe Street
Chicago, IL 60603-5780 USA
312-269-2000
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* Revision 2 corrects the report date exclusively, which was a typographical error in Revision 1.

1. INTRODUCTION

1.1. PURPOSE

Sargent & Lundy (S&L) was retained by Minnkota Power Cooperative, Inc. (Minnkota) to support the evaluation of mercury (Hg) emissions reductions in response to the pre-published rule to amend the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal-and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as Mercury and Air Toxics Standards (MATS) published on April 24, 2023 that would require additional Hg emissions reductions on the Milton R. Young (MRY) Station Units 1 and 2. As part of this evaluation, S&L assisted Minnkota in the coordination of a Hg control test campaign to determine if it is feasible to achieve incremental Hg emission reduction on a lignite-fired unit without a fabric filter that is sufficient to meet a 1.2 lb/TBtu Hg emission rate on a continuous basis.

1.2. FACILITY BACKGROUND

The MRY station is located approximately seven (7) miles southeast of Center, North Dakota or forty (40) miles northwest of Bismarck, North Dakota on ND Highway 25 at 3401 24th Street SW, Center, North Dakota 58530. MRY station provides energy to the Midcontinent Independent System Operator (MISO) system. MRY station consists of two (2) units. Both MRY units are lignite-fired Babcock and Wilcox (B&W) cyclone boilers. Both boilers fire North Dakota lignite coal supplied from BNI Coal, Ltd.'s Center Mine located in close proximity to the plant. The MRY Unit 1 single wall cyclone boiler (Caroline type, radiant natural circulation) was placed into service in 1970 and has a typical output capacity rating of 257 MWg (gross). The MRY Unit 2 opposed wall cyclone boiler (Carolina type, radiant pump assisted natural circulation) was placed into service in 1977 and has a typical output capacity rating of 470 MWg (gross). Both units utilize selective non-catalytic reduction (SNCR) and separated overfire air (SOFA) systems for NOx control, fuel additive (or halide) injection system and non-halogenated (or non-brominated) powdered activated carbon (PAC) for Hg control, dry electrostatic precipitators (ESP) for PM emissions control, and wet flue gas desulfurization (WFGD) systems for sulfur dioxide (SO_2) control.

1.2.1. Current Hg Control System Specifications

The existing Hg control system is designed to control Hg emissions below 4.0 lb/TBtu using a combination of M-Prove halide injection and non-halogenated PAC. The M-Prove is directly applied on the coal belt prior to reaching coal silos, whereas the non-halogenated PAC is injected into the duct downstream of the air pre-heater (APH). Additional information on the design of the existing fuel additive and PAC injection systems for MRY Units 1 and 2 are summarized below:

- MRY Common Non-brominated PAC Storage Silo:
    - PAC Utilized: Cabot DARCO® Hg-H non-halogenated PAC
    - Single storage silo with three (3) outlet cones or discharge connections. Each cone is connected to a feeder train (A, B, and C).
    - Feeder Train A is dedicated to MRY Unit 1
    - Feeder Trains B and C are dedicated to MRY Unit 2
    - Storage Volume: 4,200 cu.ft. (Nominal)
    - Capacity: 105,000 lbs. (based on PAC density of 25 lbs/cu.ft.)

  - Storage duration: Approximately 18 days based on silo capacity of 105,000 lbs. and total combined PAC consumption rate of 244 lb/hr (MRY Unit 1 at 86 lb/hr and MRY Unit 2 at 158 lb/hr)

- MRY Unit 1 (257 MWg)
  - Fuel Additive: ARQ (formerly ADA) M-Prove
    - Average M-Prove application rate: 6.0 ppm
    - Maximum M-Prove dosage pump rate: 18.0 ppm
  - Non-brominated PAC Injection:
    - Maximum Train A PAC injection at 100% feeder rate: 1.43 lb/min (approximately 86 lb/hr or 1.06 lb/MMacf)
    - Transport piping limited to 192 lb/hr (2.37 lb/MMacf) to avoid pluggage issues
    - PAC injected into flue gas using eight (8) lances located across the APH outlet duct.
    - The lance depths vary from 18” – 54” to provide even distribution of PAC into the flue gas stream

- MRY Unit 2 (470 MWg)
  - Fuel Additive: ARQ (formerly ADA) M-Prove
    - Average M-Prove application rate: 8.0 ppm
    - Maximum M-Prove dosage pump rate: 18.0 ppm
  - Non-brominated PAC Injection:
    - Maximum Train B and C PAC injection at 100% feeder rate: 2.64 lb/min (approximately 158 lb/hr or 1.12 lb/MMacf)
    - PAC injected into flue gas using eight (8) lances located across each of the North and South APH outlet ducts for a total of sixteen (16) lances.
    - The lance depths vary from 15” – 78” to provide even distribution of PAC into the flue gas stream

2. TEST CAMPAIGN SUMMARY

The MRY Units 1 and 2 test campaign was completed in phases to control testing variables and to accommodate vendor availability, and scheduled outages. Testing included:

- November 23, 2023 to November 24, 2023: Maximizing MRY Unit 1 capabilities of the existing M-Prove fuel additive system and non-halogenated PAC injection (at 100% feeder rate) to evaluate if the current system can meet 1.2 lb/TBtu.

- December 19, 2023 to December 20, 2023: Maximizing MRY Unit 2 capabilities of the existing M-Prove fuel additive system and non-halogenated PAC injection (at 100% feeder rate) to evaluate if the current system can meet 1.2 lb/TBtu.

- March 19, 2024 to March 23, 2024: Utilizing a rental bulk bag unloading (BBU) system provided by Motus Group tied into the existing MRY Unit 1 PAC conveying lines and injection lances to inject brominated PAC (or BPAC), ARQ's FastPAC Platinum®, at varied injection rates ranging from 100 lb/hr (or 1.23 lb/MMacf) to a maximum of 185 lb/hr (2.28 lb/MMacf) to stay below the transport piping pluggage limit. The majority of this testing also included maximizing MRY Unit 1 capabilities of the existing M-Prove fuel additive system; however, test runs on March 22 and March 23 included BPAC injection with no fuel additive usage. Individual coal samples were taken and analyzed by a 3rd party lab for determination of inlet Hg coal content.

- March 28, 2024 to April 1, 2024: Individual coal samples were taken and analyzed by a 3rd party lab for determination of inlet Hg coal content.

This testing was not able to be completed during the proposed rule's short comment period of only 60 days. Due to timing of boiler cleaning outages, time required to develop a test protocol and schedule, and coordination with multiple vendors, rental equipment availability, various site activities, and unplanned unit upsets/outages, a much longer duration was needed.

2.1. INCREMENTAL HG REMOVAL TEST RESULTS

The Hg emissions achievable based on maximizing current design capabilities using non-brominated PAC and M-Prove without any modifications is summarized below for both MRY Units 1 and 2.

Table 2-1 — MRY Units 1 and 2 Existing System Capabilities

Parameter	Units	MRY Unit 1 18 ppm M-Prove and 100% Non-brominated PAC	MRY Unit 2 18 ppm M-Prove and 100% Non-brominated PAC
Unit Load during testing	MWg	242	469
PAC Injection Rate	lb/MMacf	1.06	1.12
Avg. Sorbent Trap Hg Emissions	lb/TBtu	2.17	1.61

Based on maximizing injection capabilities of the existing systems (without any modifications), the test results show that MRY Unit 1 and MRY Unit 2 cannot achieve the proposed MATS limit of 1.2 lb/TBtu.

2.2. BROMINATED PAC PERFORMANCE

The proposed rule assumes a 90% Hg removal efficiency is feasible from all lignite units, even those equipped with an ESP.

- In the Beyond-the-Floor memo (Docket ID No. EPA-HQ-OAR-2009-0234), it states that "[g]reater than 90 percent control can be achieved at lignite-fired units at a 2.0 lb/MMacf injection rate for units with installed fabric filter and using treated (*i.e.,* brominated) activated carbon or at an injection rate of 3.0 lb/MMacf for units using treated activated carbon with installed ESPs."

- According to the proposed MATS rule, EPA reiterates that "[i]n the beyond-the-floor analysis in the final MATS rule, we noted that the results from various demonstration projects suggest that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbent at an injection rate of 2.0 lb/MMacf for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control."

The Final Rule relies on the same assumption. In EPA's 2024 Technology Memorandum, EPA finds, "In the beyond-the-floor analysis in the final MATS rule, we noted that the results from various demonstration projects suggest that greater than 90 percent Hg control can be achieved at lignite- fired units using brominated activated carbon sorbent at an injection rate of 2.0 lb/MMacf for units with installed Faric Filters for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. . . all units (in 2022) would have needed to control their Hg emissions to less than 95 percent to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the proposed, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the final MATS rule."

During the MRY Unit 1 March testing, MRY secured a temporary rental injection skid. The materials of construction of the existing PAC silo (common to MRY Units 1 and 2) is not currently compatible to store halogenated PAC. The silo would require an internal coating to prevent corrosion (but could otherwise be reused). The temporary rental injection skid avoided corrosion to the existing silo, but also allowed for decoupling MRY Unit 1 from the common PAC storage silo to prevent interfering with MRY Unit 2 Hg control operation.

To achieve a dosage rate of 3.0 lb/MMacf, an injection rate of 245 lb/hr would be required which would exceed the existing MRY Unit 1 Train A PAC injection/transport system limit of 192 lb/hr (2.37 lb/MMacf). The maximum BPAC injection rate tested was limited to 185 lb/hr (2.28 lb/MMacf) to avoid line pluggage.

The Hg emissions reductions achievable based on maximizing the use of BPAC (without any fuel additives) supplied via a temporary rental injection system tied into the existing transport piping/lances is summarized below for MRY Unit 1. A higher PAC injection rate was not possible due to maximum capability of the existing transport piping while preventing pluggage.

Table 2-2 — MRY Unit 1 Existing System Capabilities using Brominated PAC

Parameter	Units	MRY Unit 1 185 lb/hr BPAC
Unit Load during testing	MWg	257.1
PAC Injection Rate	lb/MMacf	2.28
Avg. Sorbent Trap Hg Emissions	lb/TBtu	2.57

At the current injection capabilities of the existing system (i.e. requiring minimal modifications/retrofit of the existing equipment), BPAC cannot be applied to reduce Hg emissions to 1.2 lb/TBtu.

2.3. MRY MERCURY REMOVAL EFFICIENCY

2.3.1.Lignite Coal Mercury Content

To calculate an overall mercury removal efficiency needed to control to 1.2 lb/TBtu, the coal Hg inlet must be defined.

- EPA reported the "Hg Inlet" level based on the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the Integrated Planning Model (IPM).
  - With respect to MRY, EPA reported "Hg inlet":
    - MRY Units 1 and 2: 7.81 lb/TBtu

- According to the proposed rule, EPA estimated the 2021 Hg inlet concentration from actual 2021 fuel usage and 2021 Hg emissions reported to the EPA. However, based on the 2024 Technical Memo, EPA updated the information based on 2022 information.
  - With respect to MRY, EPA "Estimated Hg inlet" content documented in 2023 and 2024 Technical Memo is summarized in the table below:

Table 2-3 — EPA Estimated North Dakota Lignite Coal Hg Inlet

Parameter	Units	2023 Technical Memo (Estimated 2021 Hg Inlet)	2024 Technical Memo (Estimated 2022 Hg Inlet)
MRY Unit 1	lb/TBtu	7.78	9.70
MRY Unit 2	lb/TBtu	7.79	9.70

- However, recent test information and other resources for the North Dakota lignite fired at MRY has indicated that significantly higher inlet Hg is experienced at MRY:
  - Within the BNI Coal, Ltd.'s Center Mine, the Kinneman Creek (KC) and Hagel (HA) beds are targeted for the coal supply for MRY. Based on the 2021 BNI coal data (constructed from Carlson reports), the avg. coal Hg content is approximately 16 lb/TBtu for KC and 15 lb/TBtu for HA.
  - The variability of the projected lignite coal quality received from the Center Mine from 2025 through 2036 is shown in the following table.

Table 2-4 — Forecasted 2025 – 2036 Center Mine Ultimate Coal Analyses (As-Received)

Fuel Parameter	Units	Average	Minimum	Maximum
Mercury Content	ppm	0.091	0.053	0.184
Higher Heating Value (HHV)	Btu/lb	6,625	6,489	6,739
Estimated Hg Emission	lb/TBtu	8.41	4.79	17.42

- Industry experience has shown that lignite coal deposits vary significantly in quality, including fuel combustion performance, mineral content, and Hg content, resulting in a coal that can change on a day-to-day basis depending on the coal seam being mined at the time. This variability was demonstrated by the range of coal analyses from MRY Unit 1 recent short-term testing in 2024 (average = 10.1 lb/TBtu, with individual results ranging from 4.9 – 18.6 lb/TBtu over the course of five (5) days of testing). Individual coal samples and how they varied across coal feeders, per day are shown in following table.

Table 2-5 — MRY Unit 1 Coal Sampling Analysis

Date	Sample	Coal Hg Inlet (lb/TBtu)				
		Feeder #1	Feeder #3	Feeder #4	Feeder #5	Feeder #7
19-Mar-24	#1@ 0730 hrs	14.5	13.0	-	-	-
	#2@ 1600 hrs	-	-	11.1	8.2	8.0
20-Mar-24	#3@ 0100 hrs	12.5	10.5	-	-	-
20-Mar-24	#1@ 0730 hrs	6.2	7.9	-	-	-
	#2@ 1600 hrs	-	-	7.2	10.1	18.5
21-Mar-24	#3@ 0100 hrs	10.9	8.1	-	-	-
21-Mar-24	#1@ 0730 hrs	14.1	7.9	-	-	-
	#2@ 1600 hrs	-	-	18.6	4.9	7.1
22-Mar-24	#3@ 0100 hrs	7.2	7.1	-	-	-
22-Mar-24	#1@ 0700 hrs	10.4	13.4	-	-	-
	#2@ 1600 hrs	-	-	6.9	11.0	11.4
23-Mar-24	#3@ 0100 hrs	9.2	7.8	-	-	-
28-Mar-24	#1@ 1030 hrs	10.2	8.3	-	-	-
	#2@ 1500 hrs	-	-	14.9	11.9	9.5
1-Apr-24	#1@ 0930 hrs	16.3	8.0	-	-	-
	#2@ 1300 hrs	-	-	6.0	12.1	12.3
	#3@ 1500 hrs	10.2	6.9	-	-	-

2.3.2. Required Mercury Removal Based on Lignite Coal Mercury Content

Based on the recent Hg fuel analyses, Hg control higher than 90% would actually be required based on the range of inlet coal Hg content expected to control to 1.2 lb/TBtu (i.e. keeping the outlet value calculated by the EPA constant). Note that control to this value does not offer any operating margin for potential exceedances that may occur due to response delays associated with coal variability. The following table identifies the required Hg control needed based on several different coal Hg content references. Based on these estimations, any Hg control approach would need to be able to accommodate a wide range of inlet Hg in order to optimize operating costs long-term.

Table 2-6 — Hypothetical Hg Emissions and Control Performance Based on Coal Analyses

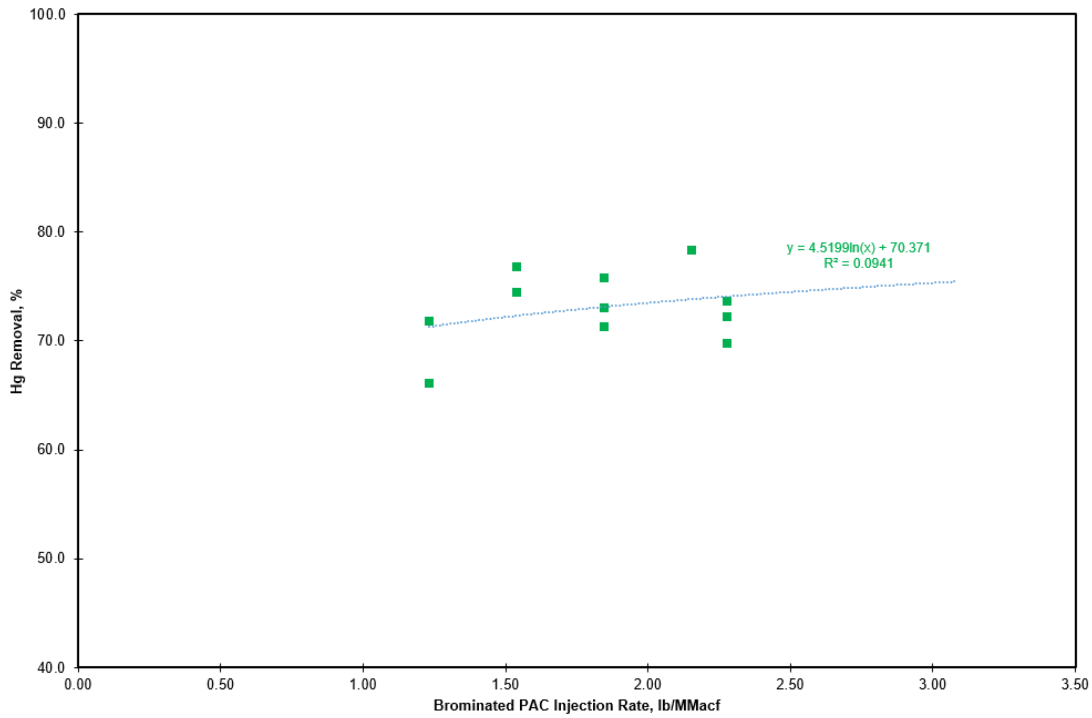
Fuel Hg Content Reference	Coal Hg Inlet (lb/TBtu)	Est. Hg Control at 4.0 lb/TBtu (%)	Est. Hg Control at 1.2 lb/TBtu (%)
EPA Technical Memo			
2023 Table 11 Docket ID. No: EPA-HQ-OAR-2018-0794[1]	7.81	48.8	84.6
2024 Table 10 Docket ID. No: EPA-HQ-OAR-2018-0794[2]	9.70	58.6	87.6
2024 MRY Unit 1 Test Campaign			
Average	10.1	60.4	88.1
Maximum	18.6	78.5	93.5
Minimum	4.9	18.4	75.5
Center Mine Forecast			
Average	8.41	52.4	85.7
Maximum	17.42	77.0	93.1
Minimum	4.79	16.5	75.0

2.3.3. Projected Mercury Removal Based 3.0 lb/MMacf BPAC

Based on the maximum BPAC rate that MRY Unit 1 was able to test due to current system limitations (185 lb/hr or 2.28 lb/MMacf), the figure below plots the estimated percent removal at the higher injection rate of 3.0 lb/MMacf BPAC using all measurements from the MRY Unit 1 March testing (with and without fuel additive usage). The plotted values demonstrate a trend line in which BPAC cannot even achieve 80% Hg removal efficiency.

[1] Benish S. et al. (January 2023). *2023 Technology Review for the Coal- and Oil-Fired EGU Source Category.* Environmental Protection Agency.
[2] Benish S. et al. (January 2024). *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category*. Environmental Protection Agency.

Figure 2-1 — MRY Unit 1 Existing System Mercury Removal Performance Capabilities using Brominated PAC



This result is contrary to EPA's assumption that BPAC at a rate of 3.0 lb/MMacf can be used to result in a 90% removal efficiency. The plotted curve shown in the figure shows a leveling off such that increasing the amount of sorbent results in diminishing improvement in Hg control. The projected curve based on the test campaign results shows this leveling off taking place somewhere less than 80% capture.

Although the plotted values do not support a conclusion that the new Hg 1.2 lb/TBtu limit can be met, further investigation into other Hg control options in combination with upgrading/optimizing existing Hg control equipment would be required to determine the lowest mercury emission rate in lb/TBtu that can be achieved on a long-term basis, considering the range of fuel Hg variability and other technological challenges inherent in capturing Hg resulting from lignite that have been documented to occur. Some proposed options for additional Hg control include:

- Increased fuel additive rate
- Improved reliability of fuel additive concentration in relation to real-time coal firing rates
- Implementation of inlet Hg monitor for improved feedback control of Hg control systems
- Improved lance design to achieve ideal distribution of PAC at all typical unit operating conditions
- Application of WFGD re-emission control additive

Further analysis, engineering, testing and equipment modifications would be necessary to determine if these options would improve Hg control. However, it is clear that adding more brominated PAC, as was assumed in the Final Rule, is not adequate, given the properties of lignite, compliance margin necessary, and limitation of mine mouth facilities in regards to fuel staging (i.e. must use coal received from mine; unable to fire only certain coals that have a more ideal or predictable range of Hg content during a 30-day rolling average).

It should be noted that the achievable Hg emission rate should not be construed to represent an enforceable regulatory or proposed permit limit. Corresponding permit limits must consider normal operating fluctuations and coal variability and take into account a minimum additional 20% margin for these fluctuations. Since a combination of new and/or upgraded control systems would be expected to be required, obtaining a guarantee from a single vendor to ensure that the unit achieves compliance below the permit limit will be challenging.

3. EPA COST VALIDITY

3.1.1. Current Hg Compliance Cost Effectiveness (4.0 lb/TBtu)

With respect to MRY, EPA estimated the cost effectiveness for current 2021 Hg emissions is shown below in an excerpt from Table 12 in 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category (Docket ID. No: EPA-HQ-OAR-2018-0794).

TABLE 12. ESTIMATED COST-EFFECTIVENESS FOR CONTROL OF MERCURY IN 2021 AT LIGNITE-FIRED EGUS

Plant Name	PM Control	Est Hg Inlet (lb/TBtu)	Est Hg In (lb)	2021 Hg (lb/TBtu)	Est Hg Out (lb)	Avg Sorbent injection (lb/MMacf)	Avg Sorbent (lb/hr)	Sorbent Cost ($/lb) **	Est 2021 Sorbent Used (lb)	Est 2021 Sorbent Cost ($)	Est 2021 Additive Cost ($) *	2021 C/E ($/lb)
Spiritwood Station 1	FF	5.03	21.3	1.9	7.9	4.0	13.2	$0.83	111,662	$92,680	$92,680	$13,776
Leland Olds 1	ESPC	7.79	91.8	2.5	29.6	3.9	45.0	**$0.97**	299,689	$290,699	$290,699	$9,343
Leland Olds 2	ESPC	7.79	142.2	3.0	55.1	2.5	55.0	**$0.97**	294,762	$285,919	$285,919	$6,563
Milton R Young 2	ESPC	7.79	130.1	3.2	53.5	1.6	43.0	$0.83	177,431	$147,267	$147,267	$3,844
Milton R Young 1	ESPC	7.78	255.5	3.2	106.2	1.3	19.0	$0.83	273,988	$227,410	$227,410	$3,046
Major Oak Power 1	FF	14.62	193.6	1.2	16.4	1.9	-	**$0.83**	161,759	$134,260	$134,260	$1,515
Major Oak Power 2	FF	14.65	207.0	1.3	18.5	1.9	-	**$0.83**	172,603	$143,261	$143,261	$1,519
Red Hills Generating Facility 1	FF	12.40	192.7	1.3	20.7	2.6	36.0	**$0.76**	259,600	$197,296	$197,296	$2,293
Red Hills Generating Facility 2	FF	12.40	209.4	1.4	22.9	2.4	36.0	**$0.76**	262,834	$199,754	$199,754	$2,141
Oak Grove 1	FF	14.60	980.0	2.0	134.9	0.1	8.0	$1.15	65,331	$75,131	$75,131	$178
Martin Lake 1	ESPC	8.22	392.7	2.3	111.0	1.0	39.0	$0.97	313,150	$303,755	$303,755	$2,156
Oak Grove 2	FF	14.88	887.2	2.6	154.2	0.3	17.0	$1.15	126,484	$145,456	$145,456	$397
San Miguel 1	ESPC	14.62	346.6	2.8	66.7	2.7	59.5	$0.97	418,050	$405,509	$405,509	$2,897
Martin Lake 2	ESPC	8.13	331.1	3.0	121.7	3.0	117.0	$0.97	809,959	$785,660	$785,660	$7,504
Martin Lake 3	ESPC	7.85	372.8	3.0	144.1	3.4	126.0	$0.97	1,046,260	$1,014,872	$1,014,872	$8,877

* Additive costs are unknown. For this analysis, the EPA assumed the additive costs are the same, annually, as the sorbent costs.
** Bolded costs are those that were provided to the EPA in the 2022 CAA section 114 information survey

Response: Flaws in EPA's cost analysis for current compliance:

- Est. Hg In (lb) & Hg Out (lb)
  - Table 12 would appear to have flipped MRY Unit 1 and Unit 2 in the table, utilizing the higher MRY Unit 2 operating conditions (heat input, hg loading, etc.) for the smaller sized Unit 1 and vice versa.

- PAC Injection Rate:
  - Table 12 Avg. Sorbent (lb/hr) – EPA noted MRY Unit 1: 19.0 lb/hr and MRY Unit 2: 43.0 lb/hr to achieve controlled Hg rate of 3.2 lb/TBtu.
  - Minnkota PAC sorbent injection rates to achieve controlled Hg rate of 3.85 lb/TBtu for MRY Unit 1 is expected to be 86 lb/hr and for MRY Unit 2 is 158 lb/hr.

- Cost of PAC:
  - Table 12 non-brominated PAC sorbent cost – EPA assumed a cost of $0.83/lb.
  - In the 2024 Technical Memo, EPA adjusted this cost down to $0.80/lb.
  - Based on MRY operational costs for 2023, non-brominated PAC sorbent cost is $0.86/lb.
  - Based on MRY operational costs for 2023, actual non-brominated PAC costs for achieving current compliance with 4.0 lb/TBtu indicated MRY Unit 1: $119,813 and MRY Unit 2: $329,328

- Cost of Fuel Additive:
    - Table 12 Est. 2021 Additive Cost – EPA noted that "Additive costs are unknown. For this analysis, the EPA assumed the additive costs are the same, annually, as the sorbent costs." And lists costs as MRY Unit 1: $227,410 and MRY Unit 2: $147,267
    - Based on MRY operational costs for 2023, actual fuel additive costs for achieving current compliance with 4.0 lb/TBtu indicated MRY Unit 1 $715,157 and MRY Unit 2: $1,574,793.
    - Based on the actual 2023 fuel additive usage rates and costs, EPA's underestimate results in $487,747 and $1,347,383 that should have been included in the cost analysis for MRY Units 1 and 2, respectively.

3.1.2.Future Hg Compliance Cost Effectiveness (1.2 lb/TBtu)

EPA calculated unit-level cost-effectiveness to meet the proposed, more stringent, emissions standard using brominated activated carbon at an injection rate of 5.0 lb/MMacf for units with an ESP for PM control or at an injection rate of 2.5 lb/MMacf for units with fabric filter for PM control.

With respect to MRY, the EPA estimated the cost effectiveness (assuming 2021 operational characteristics) is shown below in an excerpt from Table 13 in 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category (Docket ID. No: EPA-HQ-OAR-2018-0794):

TABLE 13. ESTIMATED COST-EFFECTIVENESS TO MEET A REVISED MERCURY OF 1.2 LB/TBTU AT LIGNITE-FIRED EGUS (ASSUMING 2021 OPERATIONAL CHARACTERISICS)

Plant Name	PM Control	Est Hg Inlet (lb/TBtu)	Est Hg In (lb)	Hg Out (lb)	Br-ACI rates (lb/MMacf)	Est Br-AC Sorbent Used (lb)	Br-AC cost ($)	C/E ($/lb) assuming no chemical additives	C/E ($/lb) assuming previous chemical additives
Spiritwood Station 1	FF	5.03	21.3	5.09	3.0	83,123	$95,592	$5,884	$11,589
Leland Olds 1	ESPC	7.79	91.8	14.15	5.0	385,175	$442,951	$5,702	$9,444
Leland Olds 2	ESPC	7.79	142.2	21.90	5.0	595,945	$685,337	$5,695	$8,071
Milton R Young 2	ESPC	7.79	130.1	20.05	5.0	545,753	$627,616	$5,702	$7,040
Milton R Young 1	ESPC	7.78	255.5	39.42	5.0	1,072,786	$1,233,703	$5,709	$6,761
Major Oak Power 1	FF	14.62	193.6	15.89	3.0	259,507	$298,433	$1,679	$2,434
Major Oak Power 2	FF	14.65	207.0	16.96	3.0	276,903	$318,439	$1,675	$2,429
Red Hills Generating Facility 1	FF	12.40	192.7	18.65	3.0	304,496	$350,170	$2,011	$3,145
Red Hills Generating Facility 2	FF	12.40	209.4	20.26	3.0	330,893	$380,526	$2,011	$3,067
Oak Grove 1	FF	14.60	980.0	80.56	3.0	1,315,485	$1,512,808	$1,682	$1,765
Martin Lake 1	ESPC	8.22	392.7	57.35	5.0	1,560,741	$1,794,852	$5,352	$6,257
Oak Grove 2	FF	14.88	887.2	71.55	3.0	1,168,333	$1,343,583	$1,647	$1,826
San Miguel 1	ESPC	14.62	346.6	28.45	5.0	774,167	$890,292	$2,798	$4,073
Martin Lake 2	ESPC	8.13	331.1	48.90	5.0	1,330,919	$1,530,557	$5,423	$8,207
Martin Lake 3	ESPC	7.85	372.8	56.99	5.0	1,550,850	$1,783,478	$5,647	$8,861

EPA's incremental cost-effectiveness per the 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (Docket ID. No: EPA-HQ-OAR-2018-0794) is based on a model 800 MW Gulf Coast lignite-fired EGU with a heat rate of 11,000 Btu/kWh operating at an 80% capacity factor and a Hg concentration of 25.0 lb/TBtu, resulting in an incremental cost-effectiveness of $28,176 per pound of Hg controlled. It assumes that the unit currently meets a Hg emission standard of 4.0 lb/TBtu using an injection rate of 2.5 lb/MMacf of non-brominated activated carbon at a sorbent cost of $0.80/lb and that the unit can meet a Hg emission standard of 1.2 lb/TBtu using an injection rate of 5.0 lb/MMacf of brominated activated carbon at a sorbent cost of $1.15/lb.

- Note that the example does not include fuel additives or any equipment upgrade costs.
- EPA made following changes to the calculations between 2023 and 2024 Technical Memo's:
    - EPA updated the Gulf Coast Hg concentration from 14.9 lb/TBtu (2023) to 25.0 lb/TBtu (2024). This resulted in the baseline annual uncontrolled Hg emissions to change from 919 lb Hg to 1,542 lb Hg.
    - EPA corrected the formula for conversion of sorbent injection rate from lb/MMacf to lb/hr by adjusting the conversion factor from (520 R / 785 R) to (785 R / 520 R). The conversion factor was applied incorrectly in 2023 Technical Memo.
    - EPA added an additional factor to update the formula for conversion of sorbent injection rate from lb/MMacf to lb/hr which was not previously accounted for in 2023 Technical Memo.
- For comparison with the values calculated by the EPA in Table 13, it should be noted that the 2024 calculated cost effectiveness of the 800 MW example used by the EPA to meet 1.2 lb/TBtu, without fuel additives, is $5,083 per pound of Hg controlled.

Response: Flaws in EPA's cost analysis for future compliance with 1.2 lb/TBtu:

- Est. Hg In (lb) & Hg Out (lb)
    - See previous responses on Table 12 for flipped MRY Unit 1 and MRY Unit 2 unit information/sizing and cost of fuel additive.

- BPAC Injection Rate:
    - EPA's cost analysis assumes lignite units with an ESP can achieve 1.2 lb/TBtu, which has not been demonstrated. The injection level has a direct bearing on the operational costs because it dictates the amount of BPAC necessary to reduce Hg emissions. Therefore, cost calculations are hypothetical because no project data demonstrates what the injection level would be, if 1.2 lb/TBtu is feasible.
    - Although the overall feasibility of complying with the proposed Hg limit is undetermined, the testing confirms that based on maximizing injection capabilities of the existing systems, MRY's current equipment configuration cannot achieve 1.2 lb/TBtu.

- Cost of BPAC:
    - Table 13 brominated PAC sorbent cost – EPA assumed of $1.15/lb.
    - MRY Unit 1 test campaign brominated PAC cost = $1.25/lb.

- Missing capital costs:
    - Irrespective of feasibility, EPA calculated cost-effectiveness shown in Table 13 does not include capital costs for modifying, upgrading and/or adding new equipment that would be necessary for the MRY Station due to limitations of existing equipment.
    - Modification to the existing PAC injection system, would include, but not be limited to, the following:
        - The materials of construction of the existing PAC silo (common to MRY Units 1 and 2) is not currently compatible to store halogenated PAC. The silo would require an internal coating to prevent corrosion in order to store brominated PAC.

        - New feeding equipment, transport piping and injection lances would be required to accommodate a higher injection rate.
        - As the existing PAC storage silo is shared by MRY Units 1 and 2, the higher injection rate required for achieving 3.0 lb/MMacf for both units would reduce the total storage duration to less than seven (7) days of storage. Due to the weather experienced at the site and the remote location, seven (7) days of storage is recommended for each unit. Improved equipment redundancy would also likely be required to accommodate the range of coal Hg expected to be experienced in the future. Therefore, it is likely that the existing equipment would be dedicated to MRY Unit 1, and a separate silo would be required for MRY Unit 2 to ensure adequate supply, turndown flexibility, and reliability is achieved to maintain compliance with a defined Hg emission limit.
    - As such, a new MRY Unit 2 system would be required to achieve higher injection rates of PAC. An analogous project to install Hg control equipment at a 500 MW coal-fired unit in 2021 costs roughly $5.0 million dollars, based on S&L internal mercury control database, actual project costs from recent relevant projects, and adjusted for MRY specific design.

Overall, the cost-effectiveness calculated is still a substantial under-estimation for the incremental Hg control on MRY Units 1 and 2.

- To provide an example, hypothetical MRY Unit 2 costs are summarized in the following table to underscore the magnitude of dollars that EPA failed to include in its calculations and that must be expended by Minnkota.
- Note the table below <u>does not</u> include or account for any costs associated with MRY Unit 1 system upgrades.

Table 3-1 — Example MRY Unit 2 Cost Underestimations Summary

Parameter	EPA Example Hypothetical 800 MW	EPA Assumed MRY U2 Costs 447 MW	Est. Actual MRY U2 Costs 447 MW
Current Hg Compliance (4.0 lb/TBtu) Cost [1]	\$2.6 M	\$0.3 M	\$1.9 M
Current Hg Removed	1,295 lb	77 lb	149 lb
Current C/E (\$ per lb Hg Removed)	2,004	3,845	12,754
Hg Control System Annualized Capital Cost	Not included	Not included	\$472k [2]
BPAC Cost @ 5 lb/MMacf	\$7.5 M	\$0.6 M	\$1.3 M [3]
M-Prove Cost	Not included	\$0.2 M	\$1.6 M [4]
Future Hg Compliance (@ 5 lb/MMacf) Cost	\$7.5 M	\$0.8 M	\$3.4 M
Future Hg Removed (EPA Assumed @ 1.2 lb/TBtu)	1,447 lb [5]	110 lb	216 lb
Future C/E (\$ per lb Hg Removed)	5,083	7,040	15,678
Incremental C/E (\$ per lb Hg Removed)	28,176	14,360	22,217

Note 1 – EPA example only based on sorbent. EPA assumed current compliance cost includes sorbent and chemical fuel additive. Est. actual cost based on 2023 MRY Unit 2 usage rate & pricing for both sorbent and chemical additive.
Note 2 – Cost of \$5.0 million dollars from S&L project database was annualized using a capital recovery factor calculated based on annual interest rate of 7% (pre-tax marginal rate of return on private investment, EPA Cost Manual Section 5) and 20 year evaluation period (EPA Cost Manual Section 6).
Note 3 – Cost based on EPA assumed rate but using 2023 MRY BPAC pricing.
Note 4 – Cost based on 2023 MRY Unit 2 usage rate & pricing instead of assuming same as sorbent costs.
Note 5 – Based on calculated value for EPA example inlet Hg of 1,542 lbs (current Hg coal content) – 95 lbs (future emitted amount). However, the EPA example identifies 1,468 lb for the incremental cost effectiveness calculation.

ATTACHMENT B

Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology

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NAACO
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June 19, 2023

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1. Summary of Flaws in EPA's Approach

The following is a summary of flaws in EPA's analysis, further described in detail in this report.

Particulate Matter (PM) Database

EPA's database of PM emissions is inadequate. EPA attempts to capture typical PM emissions by acquiring samples from 3 years – 2017, 2019, and 2021. For the vast majority of the units – 80% - EPA uses only 2 of the potentially available 12 quarters (in those 3 years; up to 20 quarters from 2017 to 2021) of data to construct the PM database. Further, of these limited samples. EPA cites the lowest to reflect a target PM emissions rate. EPA cites the use of the "99th percentile" PM rate in lieu of the average compensates for variability; but this approach accounts for variability within a single ("the lowest") quarter. It fails to account for long-term variability, which is affected by changes in fuel and process conditions, among others.

Lack of Design and Compliance Margin

EPA recognizes the need for margin in both design and operation (for compliance) of environmental control equipment, but ignores this concept in developing this proposed rule. The need for design margin is recognized in a 2012 OAQPS memo[1] addressing the initial developments of this very same rule, while margin for operation is considered in evaluating CEMS calibration[2] for this proposed rule. Neither design nor operating margin is considered in setting target PM standards, resulting in underestimation of number of units affected and total costs to deploy control technology. For some owners of fabric filter-equipped units, the revised rate of 0.010 lbs/MBtu eliminates any operating margin.

Inadequate Cost for ESP Rebuild

Of three categories of ESP upgrades considered by EPA, the cost for the most extensive – a complete rebuild to add collecting plate area – is inadequate. Four such major ESP rebuild projects have been implemented for which costs are reported in the public domain – and not acknowledged by EPA. Incorporating these results elevates the range of cost from EPA's estimate of \$75-100/kW to \$57-213/kW. Consequently, the "average" cost for this action used in the cost per ton (\$/ton) evaluation increases from \$87/kW to \$133/kW.

[1] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. Hereafter Hutson 2012.

[2] Parker, B., PM CEMS Random Error Contribution by Emission Limit, Memo to Docket ID No. EPA-HQ-OAR-2018-0794, March 22, 2023. Hereafter Parker 2023.

Inadequate $/ton Removal Cost

As a consequence of under-predicting capital required for ESP "rebuild," and not recognizing the need for a design and operating margin, EPA under-predicts the number of units requiring retrofit and incurred cost. As a result, in contrast to the annual cost of $169.7 M projected by the Industry Study described in this report, EPA estimates a range from $77.3 to $93.2 M. Further, the Industry Study estimates the cost per ton ($/ton) of fPM to be $67,400, 50% more than the maximum cost estimated by EPA - $44,900 /ton.

Faulty Lignite Hg Rate Revision

EPA's proposal to lower the Hg emission rate for lignite-fired units to 1.2 lbs/TBtu is based on improper interpretation of Hg emissions data – both in terms of the mean rate and variability. EPA's projection that 85 and 90% Hg removal would be required for the proposed rate is incorrect, with up to 95% Hg removal required for some units – a level of Hg reduction not feasible in commercial systems. In addition to the variability of Hg content in lignite, EPA ignores the deleterious role of flue gas SO_3 in lignite-fired units, which compromises sorbent performance and effectiveness – even though this latter barrier is recognized and cited by EPA's contractor for the IPM model.[3]

Faults in IPM Modeling

IPM creates a flawed Baseline scenario that does not adequately measure the impacts of the proposed rule. Most notably, IPM err in the number of coal units that would be retired in both 2028 and 2030; as a consequence, EPA underestimates the number of units subject to the proposed rule. Also, IPM unrealistically retrofitted 27 coal units with carbon capture and storage (CCS) in 2030. Consequently, IPM modeling results of the Baseline likely understate the compliance impacts of the proposed rule.

[3] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

2. Introduction

The Environmental Protection Agency (EPA) is proposing to amend the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units (EGUs), otherwise known as the Mercury and Air Toxics Standards (MATS). The specific emissions limits being revised address the filterable particulate matter (fPM) standard (which is the surrogate standard for non-mercury (Hg) metal HAPs); the Hg standard for lignite-fired units; fPM measurement methods for compliance; and the definition of startup. This report provides a review and evaluation of EPA's approach to selecting the revised fPM standard, the capital and annual costs for achieving the proposed revised standard, and the cost per ton ($/ton) to control non-Hg metal HAPs; and a critique of EPA's basis for proposing an Hg limit of 1.2 lbs/TBtu for lignite-fired units. This document also provides information supporting EPA's decision to retain the present Hg limit for bituminous and subbituminous coal.

The proposal to lower fPM and Hg limits is premised on EPA's interpretation of data related to the cost and capabilities of PM and Hg emission control technologies. EPA reports to have conducted realistic assessments of PM and Hg emissions and control technology capabilities in support of their analysis. EPA's assumptions are reported in the MATS_RTR_Proposal_Technology Review Memo[4] where EPA describes the PM database they developed, the cost and control capabilities of upgrades to electrostatic precipitators (ESPs) and fabric filters, and their understanding of the key factors that affect Hg emissions in bituminous, subbituminous, and lignite coal - and how the latter are alike or differ.

Many of EPA's assumptions are contrary to data in their possession or strategies previously adopted by EPA, but not considered. EGUs have been reporting fPM compliance data to EPA since MATS became applicable to them – i.e., for the vast majority of EGU, April 2015 or April 2016 for units that obtained a one-year extension. However, EPA's effort to "mine" fPM emissions data from prior years provides a sparse, inadequate database that does not reflect operating duty nor account for inevitable variability; further EPA misinterprets this information. No design or operating margins are considered in setting fPM (the same is true for lignite Hg emission rates). The cost to upgrade ESPs to meet the proposed limits is inadequate for the most significant modification EPA envisions – the complete ESP Rebuild. The cost to deploy enhanced operating and maintenance (O&M) actions on existing fabric filers is inadequate. Regarding revised Hg limits for lignite coal, EPA does not recognize the differences in lignite versus Powder River Basin (PRB) subbituminous coal that effect Hg control. EPA draws an incorrect analogy between PRB and lignite, improperly assuming the Hg removal by carbon sorbent observed with PRB can be replicated on lignite.

[4] Benish, S. et. al., 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, Memo to Docket ID No. EPA-HQ-OAR-2018-0794. January 2023. Hereafter RTR Tech Memo.

The remaining sections of this report detail the findings summarized in Section 1, and are as follows:

- Section 3 describes EPA's approach to assembling their fPM database, and the flaws and weaknesses in their approach.
- Section 4 evaluates the fPM rates assigned by the database for the EPA analysis.
- Section 5 evaluates EPA's cost bases for the proposed fPM revised standard, and compares these to the realistic assumptions used in the Industry Study described in the paper.
- Section 6 addresses EPA's proposal to lower Hg from lignite-fired units to 1.2 lbs/TBtu, delineating the shortcomings in EPA's approach and assumptions.
- Section 7 provides historical data for Hg emission from non-low rank fuels, showcasing the inherent variability in the 30-day rolling average.
- Section 8 reviews the IPM modeling analysis conducted by EPA to support this rule.
- Appendix B presents examples of PM emission timelines for a limited number of units[5] that show how EPA's sparse database does not capture the authentic "PM signature" of the units.

[5] We reviewed data for a limited number of units because the comment period was very short and did not allow adequate time to undertake a more thorough review. EPA has all the data and in our opinion should have conducted such an analysis for every unit at issue.

3. Description of EPA Reference PM Database

Section 3 describes the PM database assembled by EPA which serves as the basis for the proposed NESHAP rule. Section 3 first describes the coal fleet inventory reflected, and then identifies shortcomings of this database concerning (a) selection of the sample year and quarter, (b) number of samples considered, and (c) data analysis.

3.1 Coal Fleet Inventory

EPA projects that a total of 275 generating units will be operating at the compliance date of January 1, 2028, representing a reduction from the present (2023) operating inventory of approximately 450 units. EPA identified the 275 units based on their estimate of unit retirements and units planning to switch to natural gas by the compliance date. EPA accounted for these assets not as individual units, but in terms of the number of reporting monitors to the Clean Air Markets Division. As 27 units employ common stack reporting, the data presented by EPA in the draft rule and RTR Tech Memo consider 248 discrete data points that reflect the 275 units. This analysis will adopt the same reporting methodology.

EPA's selection of 275 units contains 22 units that have publicly disclosed plans to retire or switch to natural gas by the compliance date of January 1, 2028. For the purposes of this analysis, these units are retained in the database so the results can be more readily compared.

Figure 3-1 depicts the installed inventory projected by EPA, presented according to the suite of control technology. The first two bars (from the left) report units equipped with ESPs as the primary PM control device in the following configurations: a total of 54,116 MW for an ESP followed by a wet FGD; and a total of 16,346 MW with an ESP only. The next 3 bars describe the total inventory equipped with a fabric filter in the following three configurations: 12,194 MW with the fabric filer as the sole device; 20,206 MW with a fabric filter followed by a wet FGD, and 19,995 MW where the fabric filter is preceded by a dry FGD process. Consequently, the bulk of the inventory (70,462 MW) will employ an ESP as part of the control scheme, with 52,395 MW employing a fabric filter for PM. Given the role of wet FGD in PM emissions – in most cases such devices will reduce PM by approximately 50% - more than half (74,322 MW) employ wet FGD as the last control step.

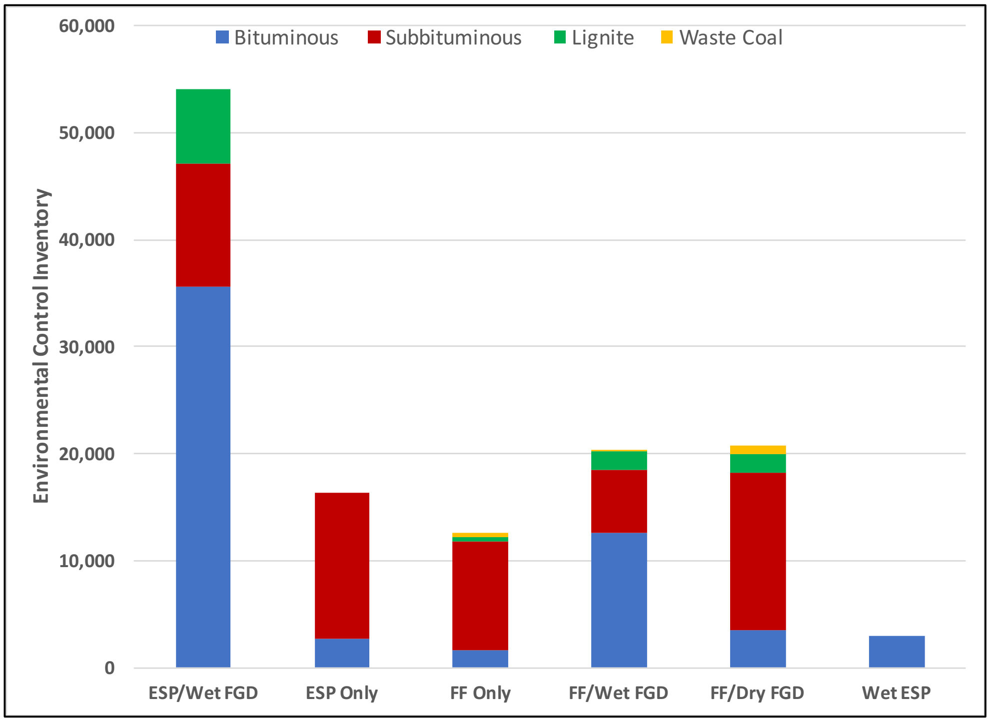

Figure 3-1. Inventory of EPA-Project 2028 Fleet by Control Technology Suite

3.2 Database Characteristics

Several characteristics of EPA's database severely compromise the quality of the analysis. These are the (a) selection of sampling year and quarter and (b) number of samples used.

3.2.1 Selection of Sample Year and Quarter

EPA does not describe the rationale for the limited data selected. The selection of three reference years (2017, 2019, and 2021) from at least 5-6 years of data readily available to EPA, and the sampling periods within each year (typically the 1st or the 3rd quarter even though all quarters are generally available) are not discussed. EPA extracts data from the year 2021 using a different approach from the years 2019 and 2017 without explanation. EPA states for 2021 that 2 quarters of data are utilized (always the 1st and the 3rd). For 2019, EPA reports utilizing data from "quarters three and occasionally four" while for 2017 EPA reports data acquired from "variable quarters."[6]

The rationale for the irregular selection of quarters is not stated. For 2021, the first and third quarters are selected with no technical basis. For 2019, the selection of quarters three and "occasionally" four does not replicate the time periods selected for 2021. For 2017, there is no description of the quarters or selection criteria.

EPA ignores a rich field of data that could support a much more robust and reasonable analysis.

[6] RTR Tech Memo, page 2.

3.2.2 Number of Samples

The number of discrete data points in EPA's Reference Database – defined by the number of operating quarters – is extremely limited. EPA's description of the sampling approach[7] is as follows:

Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed because data for all affected EGUs subject to numeric emission limits had been previously extracted from CEDRI. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019).

Figure 3-2 shows most monitor locations — 193 of the 245 — are characterized by only 2 quarters of data, which is inadequate compared to the 16 or 20 EPA has access to. The distribution of quarters selected by EPA according to either CEMS or stack test measurement for all 245 locations is shown. The second largest category is 33 units characterized by 4 quarters.

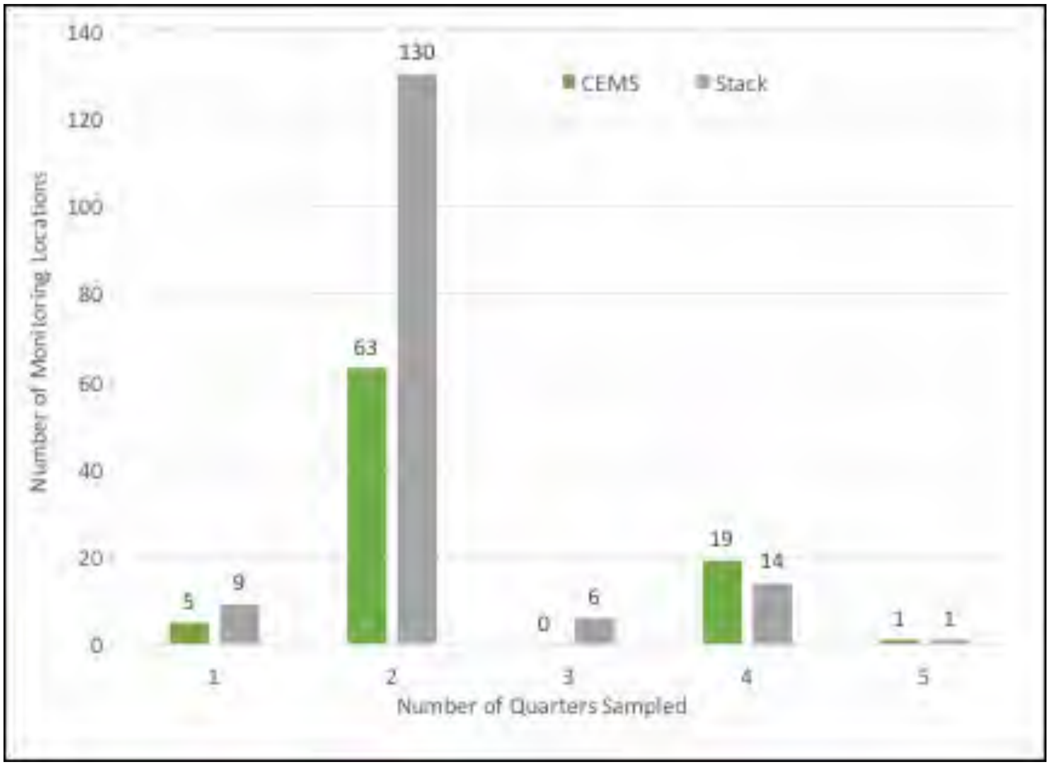

Figure 3-2. Numbers of Quarters Sampled by EPA for Use in PM Database

[7] RTR Tech Memo, page 2.

Additional depictions of the data (not shown) reveal that only nine units are described by data in 2017, and 187 units by data from 2019. Only 41 units are described by data in 2021; the lack of data in 2021 was intentional as EPA considered this year only if data from 2017 or 2019 showed the unit exceeding the 0.010 lbs/MBtu proposed limit.[8] In other words, EPA looked at 2021 only when it was trying to find an emission rate less than 0.010 lbs/MBtu for a unit.

3.2.3 PM Data Selection and Analysis

EPA does not explain the methodology chosen to reflect each quarters' emission rate, using at least two methods, depending on the year. EPA followed a four-step process to construct its database to select the "base rate" for each unit. The process is described as follows:

Step 1: Quarter Selection. EPA looked at 2-4 (usually 2) quarters for each unit. EPA states: "Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed …. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019)."[9]

As noted previously, EPA considered Q1 and Q3 2021 data solely to find a PM rate lower than 0.010 lb/MMBtu, and further explained: "The quarterly 2021 data summarizes recent emissions and also reflect the time of year where electricity demand is typically higher and when EGUs tend to operate more and with higher loads."[10]

Step 2. Select Single Quarter. From the candidate quarters identified in Step 1, EPA selected a single value, using criteria specific for each tests methodology:

- *PM CEMS*: for quarters in 2017 and 2019, EPA selected the 30-day average observed on the last day of the quarter; for quarters in 2021, EPA determined the average of the 30-day rolling averages observed in that quarter.
- *Stack Tests*: EPA took the average of the multiple (usually 3) test runs.

Step 3. Select Lowest Quarter. EPA selected the "lowest quarter" PM rate from the quarters selected in Step 2.

Step 4. Determine PM of 99th Percentile. For this lowest quarter per Step 3, EPA calculated the statistical percentile values as observed over the entire quarter. The methodology varied on whether PM CEMS or stack test data was provided. For PM CEMS, the percentiles were calculated for all 30-day rolling averages in the quarter. For stack tests, the percentiles were calculated for the typically 3 test runs.

[8] Personal communication: Sarah Benish to Liz Williams, April 28, 2023. "*Data for 2021 was mined only for the EGUs that showed 2017 or 2019 fPM data above 1.0E-02 lb/MMBtu. We did not mine 2021 PM data for EGUs not expected to be impacted by the proposed fPM limit.*"

[9] RTR Memo, page 2.

[10] Ibid.

The results are reported in Appendix B of the Technology Review Memo. The 99th percentile rate was chosen as the "base rate," supposedly to account for variability within the "lowest quarter."

EPA does not describe why data selected was restricted to the years 2017, 2019, and 2021. EPA does not explain why 2021 data was limited to the 1st and 3rd quarters, 2019 data was limited to the 3rd and occasionally the 4th quarter, while 2017 data from variable quarters could be utilized.

Of concern is the limited subset of data used for this analysis – Figure 3-2 showed that for 80% of the units the lowest is selected from only two samples. EPA states "By using the lowest quarter's 99th percentile as the baseline, the analyses account for actions individual EGUs have already taken to improve and maintain PM emissions."[11] EPA states employing the PM rate at the 99th percentile –reflecting approximately the highest data within that quarter – remedies any bias.[12]

There is no basis for this statement. EPA is assuming that because a unit emitted fPM during a single quarter at a particular level, the lowest such level must necessarily reflect "actions individual EGUs have already taken to improve and maintain PM emissions," and therefore each EGU must be able to replicate that rate in every quarter going forward, indefinitely. Also, EPA ignores the unavoidable variability in emission rates: the "actions individual EGUs have already taken to improve and maintain PM emissions" are not the only factor that determines fPM emissions rate. The factors that affect fPM rates are numerous and include but are not limited to the following: coal quality (e.g., chemical composition and ash content) which varies within a single mine; variation in temperature within an ESP; content of SO_3 and trace constituents that determine ash electrical resistivity; physical conditions (spacing) of collecting plates and emitting electrodes; effectiveness of the rapping "hammers" that dislodge collected ash from the collecting plates; and physical properties of the collected ash layer that define ash re-entrainment. Further, boiler operation will influence ESP performance, most notably unit duty (i.e., relatively stable operating level for a "baseload" unit versus more load changes for an intermediate unit or a unit operating in peaking mode), operating level, and load "ramp" rate. Achieving the "least emission" rate observed during a quarter that EPA selected is not necessarily feasible at other times and under other conditions.

3.2.4 Example Cases

Figure 3-3 presents an example that demonstrate the shortcomings of EPA's approach. Figure 3-3 presents PM data from Coronado Generating Station Units 1 and 2 reflecting all operating quarters from 2017 through 2021. Both the average PM rate and the 99th percentile from each quarter are presented for 20 quarters of operation over the 4-year period. Figure 3-3 also identifies the two samples EPA selected from 2017 Q3 and 2019 Q3 as representative of low fPM rate, with the latter as the "least" – and the 99th-percentile reporting 0.0086 lbs/MBtu. Figure 3-3 shows EPA's two samples do not capture the full character of Coronado operating duty (with the red dotted line denoting the PM rate selected as representative of the units'

[11] RTR Tech Memo, page 4.
[12] Ibid.

capabilities to control PM). These quarters as selected by EPA are far from representative of unit operations or capabilities: among 20 quarters for which data are available, the units' 90th percentile fPM rates exceed the 0.0086 lbs/MBtu rate EPA selected for 16 quarters. Ten out of 20 quarters showed 90th percentile fPM rates exceeded the proposed standard of 0.010 lb/MBtu.

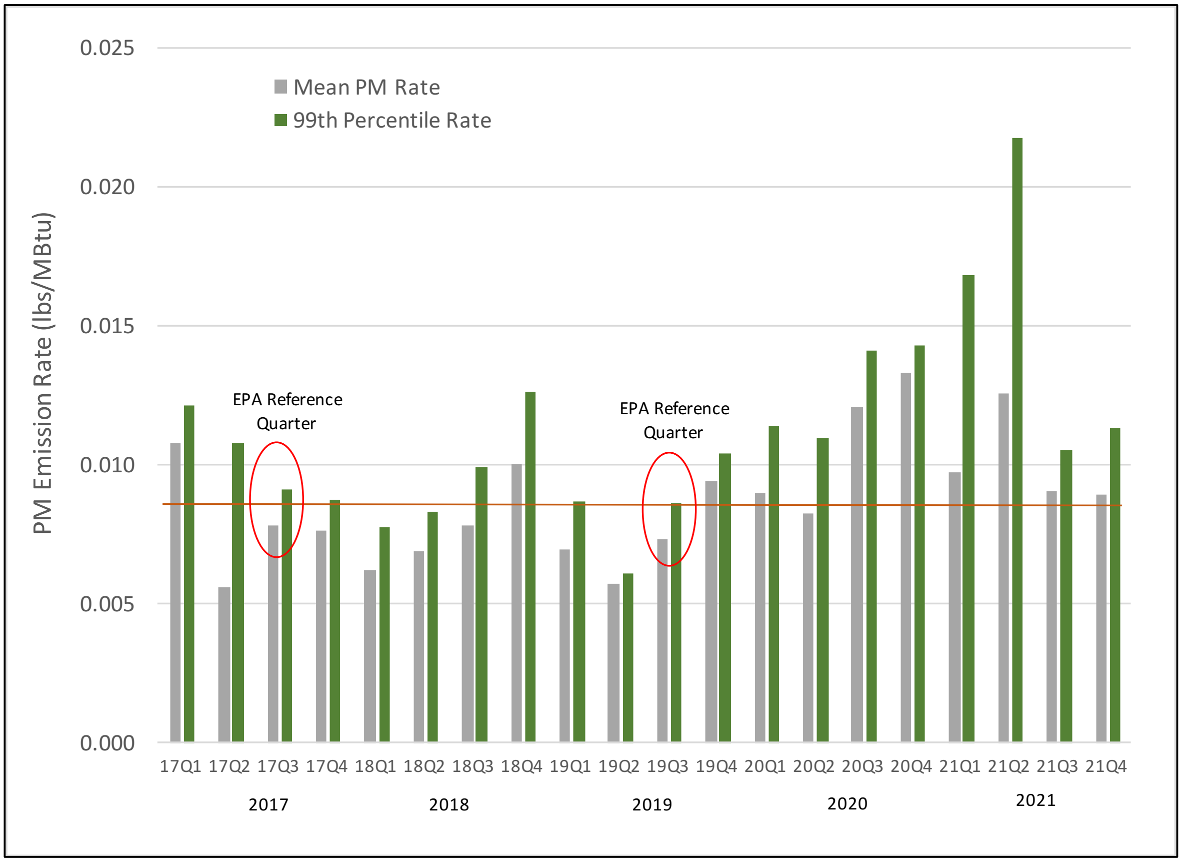

Figure 3-3. Coronado Generating Station: 20 Operating Quarters

Coronado Units 1/2 show how selecting the least PM rate of any quarter, and adopting the 99th percentile PM rate within that quarter, does not capture the variability in fPM emission rates, which are affected by the variability of coal and operating conditions, among others. These examples demonstrate that EPA used best-case fPM data from both compliance measures (continuous monitor and performance test data).

Additional examples are presented in the Appendix B to this report.

3.3 Conclusions

- EPA's database is sparse and does not fully capture operating duty. Of the 275 units and approximately 250 monitoring locations, the vast majority – 80% - are characterized by only two samples.

- Selecting the lowest quarter - "one" of what in most cases are "two" samples - fails to capture the operating profile of the unit, and presents a serious deficiency in representing operations. EPA's approach of considering the 99th percentile within a quarter is inadequate to assess variability, particularly that induced by fuel composition, as such fuel changes are observed over a characteristic time of years and not several months.

- The use of statistical means within one quarter does not capture the multi-month variances in coal composition, seasonal load, and process conditions that are not constrained to 3-month events.

- An improved, robust database would allow observing variation between– as opposed to within – operating quarters, to better reflect variations and uncertainties in operating duty and fuel supply.

4. Coal Fleet PM Emissions Characteristics

Section 4 characterizes the coal-fired fleet selected to represent the PM emissions

The emission control technologies on the 275 units projected by EPA to be operating in 2028 present a variety of approaches to lower fPM emission limits – with implications for upgrades and actions that would be required to meet a revised standard for fPM. This subsection presents the distribution of control technology by ability to operate below the revised PM limits for the units in EPA's database. By necessity, this analysis uses EPA's database (both for a discussion of expected or achievable fPM emission rates and the units projected to operate in 2028 and later), and such use does not represent an endorsement or acceptance of EPA's approach. As discussed above, EPA's analysis of expected/achievable fPM emission rates is inadequate. And as discussed later in this report, EPA's selection of units that would continue to operate after 2028 is flawed: it contains multiple errors; and EPA's post-IRA IPM analysis is inaccurate.

Figure 4-1 is used to present our analysis.

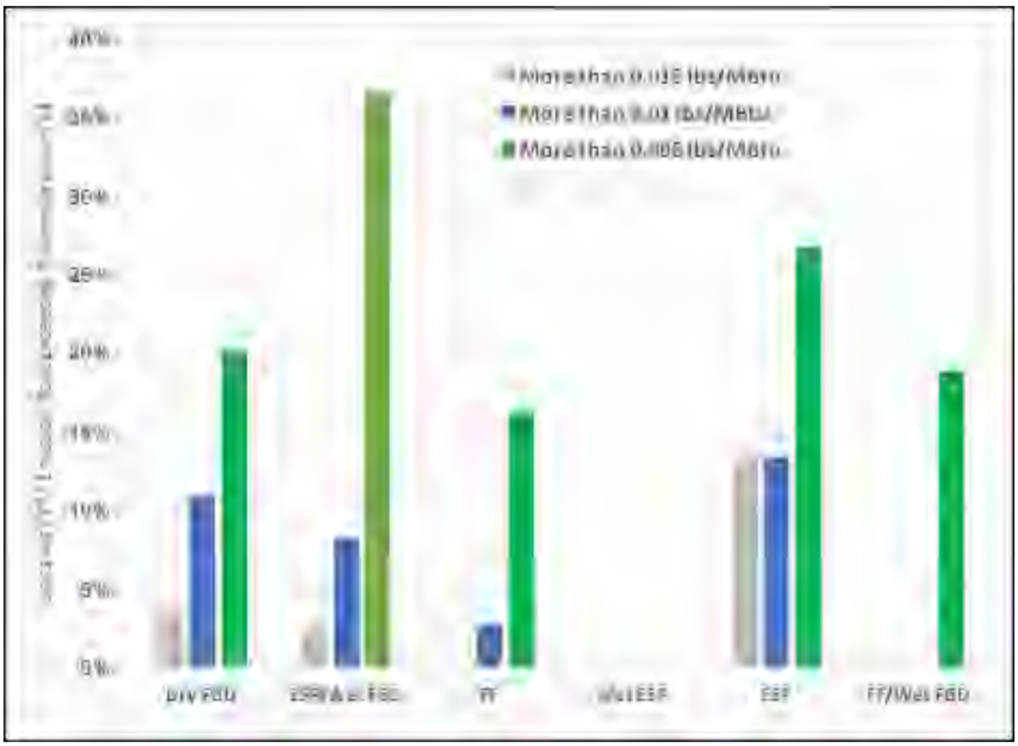

Figure 4-1. Fraction of Units Exceeding Three PM Rates: By Control Technology

Figure 4-1 presents for five control technology configurations the percentage of units that emit (according to EPA's chosen "base rate") above the following PM emission limits: 0.015 lbs/MBtu, 0.010 lbs/MBtu, and 0.006 lbs/MBtu. The control technologies are (a) dry FGD with a fabric filter, (b) ESP followed by a wet FGD, (c) fabric filter alone (employing low sulfur coal or multi-unit station-averaging to meet an SO_2 limit), (d) wet ESP as the last control device, (e) ESP alone (employing low sulfur coal or multi-unit station-averaging to meet an SO_2 limit), and (f) fabric filter followed by a wet FGD.

In Figure 4-1, the proportion of units in the inventory that exceed the contemplated fPM rate is proportional to the height of the bar; a higher bar implies a greater fraction of units in the inventory exceed the contemplated fPM rate. Thus:

4.1.1 PM Rate of 0.015 lbs/MBtu

Units in three categories exceed this highest contemplated rate – those with an ESP alone, a dry FGD followed by a fabric filter, and an ESP followed by a wet FGD. The latter category of ESP/wet FGD benefits in that actions within the absorber tower – although not designed to removed fPM – can under some conditions remove fPM. Data describing PM removal via wet FGD is sparse but suggests 50% removal can be observed.

4.1.2 PM Rate of 0.010 lbs/MBtu

The number of units in each of the three preceding categories exceeding this rate increases – there is no change for the category of ESP-alone, but the number of units exceeding this rate more than triple for dry FGD/fabric filter and ESP/wet FGD. No units with fabric filter/wet FGD or a wet ESP emit at greater than this rate.

4.1.3 PM Rate of 0.006 lbs/MBtu

The number of units exceeding a rate of 0.006 lbs/MBtu increases with this most stringent contemplated rate. More than 1/3 of the units with ESP/wet FGD and ¼ of ESP- only cannot meet this rate, with fabric filters either operating with dry FGD (20%) or alone (16%) not achieving this target. Almost 20% of those with fabric filter/wet FGD units emit greater than this value.

In conclusion, within six major categories of control technology, units equipped with fabric filters achieve the lowest PM rates. Units with ESPs – either operating alone or with a wet FGD- represent the highest fraction of their population that exceed the strictest contemplated rate. Units with fabric filters – operating alone, or as part of a wet or dry FGD arrangement – are among the lowest exceeding the strictest contemplated PM rate. As noted previously, this analysis used EPA's database (as reflected in Appendix B of the RTR Tech Memo) out of necessity, and such use does not represent an endorsement or acceptance of EPA's approach.

5. CRITIQUE OF COST-EFFECTIVENESS CALCULATIONS

Section 5 addresses the cost effectiveness ($/ton basis) estimated to reduce the PM emission rate to EPA's proposed limit of 0.010 lbs/MBtu, and the alternative limit of 0.006 lbs/MBtu. EPA has conducted this calculation with inputs based on analysis by Sargent & Lundy (S&L)[13] and Andover Technology Partners (ATP).[14] EPA's results are presented in both Table 3 of the proposed rule and in Table 7 of the RTR Tech Memo.

This section reviews EPA's calculation methodology, critiques inputs of the EPA Study, and presents results of an Industry Study that utilizes realistic costs. Results from EPA's evaluation and the Industry Study addressing the 0.010 lbs/MBtu and 0.006 lbs/MBtu PM rates are compared.

5.1 EPA Evaluation

5.1.1 EPA Study Inputs

The EPA study used both the PM database described in Section 3 and cost and technology assumptions derived by the above-mentioned S&L and ATP references. As noted in Section 2, EPA's sparsely-populated database is inadequate from which to base a revised PM rate that represents a significant reduction in PM emissions but is achievable in long-term duty.

The analyses by S&L and ATP provide capital cost for three categories of ESP upgrades, improvements to fabric filter operating and maintenance (O&M) and associated costs, capital requirement for fabric filter retrofit and associated O&M cost. Most of the analysis is premised on the costs and PM removal performance of ESP upgrades as defined by S&L. It should be noted S&L did not provide specific projects with publicly available data as the basis of their assumptions.

The most significant shortcoming of EPA's assumptions is low capital estimates for the most significant ESP upgrade - the "ESP Rebuild" scenario. In contrast to the generalizations of the S&L memo, Table 5-2 reports publicly documented costs incurred for "ESP Rebuild." Equally significant, EPA ignores the inherent variability of fPM and FGD process equipment by not utilizing a design or operating margin in selecting the value of fPM rates that would require operator action. This is counter to EPA's prior acknowledgement of the use of margin in the initial rulemaking for MATS[15] and recent observations as to CEMS calibration.[16] It is also contrary to basic operation goals: no source operates at the applicable standard; a compliance

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[13] PM Incremental Improvement Memo, Project 13527-002, Prepared by Sargent & Lundy, March 2023. Hereafter S&L PM Improvement Memo.

[14] Analysis of PM Emission Control Costs and Capabilities, Memo from Jim Staudt (Andover Technology Partners) to Erich Eschmann, March 22, 2023. Hereafter ATP 2023.

[15] Hutson 2012.

[16] Parker 2023.

margin is always necessary, at least to account for unavoidable variability of performance in the real world. By ignoring the need for margin, EPA's evaluation under-predicts the number of units that would be retrofit with new or upgraded control technology to meet the target rate.

These and other critiques of EPA's approach are discussed subsequently.

Shortcomings in EPA inputs compromise the results of their analysis. These shortcomings, as well as other observations, are summarized as follows:

ESP Upgrade. Three categories of ESP upgrade are proposed by EPA. The most significant shortcoming relates to the "ESP Rebuild" category in which - as described by S&L – additional plate area is added to the ESP. The addition of collecting surface area will require major changes to – or demolition and complete rebuilding of – the gas flow confinement that houses the existing collecting plates. Also, these process changes require specialized labor for fabrication and installation that may be limited in availability. The costs suggested by S&L (without citation of references) - $75-100/kW –are low when compared to publicly disclosed costs from similar projects.

Fabric Filter O&M. Fabric-filter-equipped units that emit greater than 0.010 lbs/MBtu are assumed to adopt enhanced O&M practices. These enhanced practices consist of (a) upgrading filter material to higher quality fabrics, such PTFE, and (b) increasing the replacement frequency so that filters are replaced on a 3-year basis. The cost premium for this action, based on analysis by ATP, does not consider the additional manpower costs for the more frequent replacement.

Fabric Filter Construction. EPA's range of capital cost for retrofit of fabric filter technology is consistent with industry experience.

Design/Compliance Margin. A premise of environmental control system design is accounting for variability due to many factors, including, for example, variations in fuel composition, operating load, and process conditions. Such variability is generally addressed by a design/compliance margin – selecting a target emission rate less than mandated by a standard. The concept of design/compliance margin is broadly applied in the industry, and was acknowledged in a 2012 EPA memo summarizing the range of margin adopted by various process suppliers, with a minimum cited as 20-30%.[17] EPA did not adopt a design/compliance or operating margin in selecting fPM emission rates for a revised fPM standard in this evaluation, despite the fact that elsewhere in the record of this proposal EPA acknowledges a typical "operational target" of 50% of the limit.[18] Because of its assumption of no design/compliance margin whatsoever, EPA presumes that units that report an operating fPM of 0.010 lbs/MBtu – based on EPA's sparse database - require no investment to meet the proposed standard of 0.010 lb/MBtu.

[17] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012.

[18] Parker 2023.

Separate from the preceding issues, EPA did not disclose the capacity factors assumed in the analysis. The capacity factor can be inferred from the tons of PM removed as reported in Appendix B of the RTR Tech Memo; this requires acquiring heat input and net plant heat rate from AMPD and EIA data.

5.1.2 EPA Results

Table 5-1 presents results of EPA's evaluation.

Table 5-1. Summary of EPA Results

EPA Study					
Unit Affected	Tons fPM Removed	Annual Cost ($M/y)	$/ton fPM (average)	Non-Hg metallic HAPS Removed (tons)	$/ton non-Hg metallic HAP ($000s)
Target: 0.010 lbs/MBtu					
20	2,074	77.3-93.2	37,300-44,900	6.34	12,200-14,700
Target: 0.006 lbs/MBtu					
65	6,163	633	103	24.7	25,600

Proposed Limit: 0.010 lbs/MBtu. EPA estimates 20 units in the entire inventory are required to retrofit some form of ESP upgrade. The number of units with existing fabric filters required to enhance O&M is not identified, nor is their cost. EPA estimates a range in annual cost to implement the ESP and fabric filter O&M enhancement of $77.3 to 93.2 M/yr, with the range determined by the range in cost and performance of each option as described by S&L.[19] This total annualized cost translates into an average fPM removal cost effectiveness of $37,300 - $44,900 per ton of fPM and $12.2M -$14.7 M per ton of total non-Hg metallic HAPs. These steps remove a total of 2,074 tons of fPM (6.34 tons of total non-Hg metallic HAPs) annually.

EPA did not consider in its analysis the potential impact of the capital cost of major controls construction or upgrades (i.e., ESP rebuilds for most of the 20 units; new Fabric Filters for the two Colstrip units) on the viability of the units at which such rebuilds would occur. Appendix Figure A-1 presents the capital required for each unit as designated by EPA for upgrade – requiring an investment likely prohibitive for continued operation.

Potential Limit: 0.006 lbs/MBtu. EPA estimates 65 units in the entire inventory are required to retrofit a fabric filter or deploy enhanced O&M to an existing fabric filter. EPA estimate an annual cost of $633 M/yr will be incurred, at an average cost effectiveness of $103,000 per ton

[19] S&L PM Improvement Memo.

of fPM and $25.6 M per ton of total non-Hg metallic HAPs. These steps remove a total of 6,163 tons of fPM (24.7 tons of total non-Hg metallic HAPs) annually.

5.2 Industry Study

The Industry Study alters several assumptions to reflect actual, documented cost data and the necessity of a design/compliance margin. Table 5-2 presents these results.

5.2.1 Revised Cost Inputs

The modified cost inputs necessary to reflect authentic conditions ESP upgrade and fabric filter operation are discussed as follows.

ESP Upgrades. The three categories of ESP upgrades are assessed as follows.

Minor Upgrades (Low Cost). Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Minor Upgrade are assigned a $17/kW cost to derive an average of 7.5% removal of fPM.

Typical Upgrades (Average Cost). Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Typical Upgrade are assigned a $55/kW cost to derive an average of 15% fPM removal.

ESP Rebuild (High Cost). The cost range for this activity as estimated by S&L does not reflect that reported publicly for four projects that represent the “ESP Rebuild” category. Two projects were completed at the AES Petersburg station – the complete renovation of the ESPs on Units 1 and 4[20] for which S&L provided engineering services. The cost for this work has been publicly reported in 2016-dollar basis. Two additional major ESP upgrades were implemented by Ameren at the Labadie station unit in 2014 – with costs publicly reported.[21]

Table 5-2 summarizes the cost incurred for the four major ESP retrofits, including costs in the year incurred and escalated (using the Chemical Engineering Process Cost Index)[22] to 2021. Table 5-1 shows a cost range of $57-209/kW, with 3 of the 4 units incurring a cost exceeding $100/kW. These costs significantly exceed EPA’s maximum for this range.

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[20] State of Indiana – Indian Public Utility Commission, Cause No. 44242, August 14, 2013. See Appendix, electronic page 50 of 51.

[21] Ameren Missouri Installs Clean Air Equipment at its Labadie Energy Center; https://ameren.mediaroom.com/news-releases?item=1351

[22] https://www.chemengonline.com/pci-home#:~:text=Since%20its%20introduction%20in%201963,from%20one%20period%20to%20another.

Table 5-2. ESP Rebuild Costs: Four Documented Cases

Owner/Station	Unit	Basis Year	2021 ($/kW)
AES/Petersburg	1	2016	117
AES/Petersburg	4	2016	57
Ameren Labadie	1	2014	192
Ameren Labadie	2	2014	209

Consequently, the range of ESP rebuild costs is adjusted to $57-209/kW, and the mean value of $133/kW (2021 basis) selected to represent this category of upgrade.[23]

FF O&M. A fabric filter O&M cost was derived for existing units, based on the assumption by S&L that filter material will be upgraded, as well as the frequency of filter replacement. An increase in cost – reflected as fixed O&M – of $515,000 is estimated for a 500 MW unit. This cost premium is comprised of higher material cost of $425,000 to upgrade filter material to PTFE fabric and an additional $90,000 for installation labor. This cost premium as is assigned to existing units based on generating capacity, and using a conventional "6/10th" power law.

The revised Industry Study costs are based on (a) gas flow volume treated, (b) surface area of filter required based on the unit design, (c) unit cost of filter (e.g. $ per ft^2 of cleaning surface), and (d) replacement rate of filter material. Gas flow treated for each unit was determined using the quantitative relationships derived by S&L for fabric filter cost evaluation developed for the IPM model.[24] Filter surface area was not defined for each unit as dependent on the specific air/cloth ratio; rather a fleet air/cloth ratio of 5 – a mean value between conventional and pulse-jet design concepts – is selected. The unit cost for fabric was selected (at $4.00/$ft^2$) per ATP analysis. Per S&L's IPM fabric filter costing procedure[25] and the EPA-sponsored review of filter material cost,[26] the increase in cost for enhanced O&M is derived. The cost to upgrade material, accelerate filter replacement (from 5 to 3 years) and supporting cages (from 9 to 6 year) intervals is estimated as $425K per year for a reference 500 MW unit.

Fabric Filter Capital Cost. EPA proposed a capital cost to retrofit a fabric filter as $150-$360/kW. The cost range offered by EPA is consistent with industry experience and is used in this study.

EPA did not share the incremental operating cost incurred by the retrofit fabric filters. The Industry Study adopted fixed and variable operating costs from the previously cited S&L fabric filter cost estimating procedure. For the assigned inputs, the S&L evaluation projects a fixed

[23] Colstrip Units 3 and 4 are equipped with legacy FGD that combine removal of SO2 and PM in a wet venturi; there is not an ESP option to upgrade. Fabric filer retrofit is the only option; as Colstrip represents an atypical case the costs are reported in the category of Major ESP upgrade.

[24] IPM Model – Updates to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology, Project 13527-001, Sargent & Lundy, April 2017. Hereafter S&L Fabric Filter 2017.

[25] Ibid.

[26] ATP report.

O&M of $0.27/kW-yr and a variable operating cost of 0.48 $/MWh. The variable O&M cost is mostly comprised of filter replacement at the accelerated rate described, and auxiliary power.

Design/Compliance Margin. EPA in two public documents address – and apparently recognize – the need for design/compliance margin.[27] The use of design/compliance margin was acknowledged in a 2012 EPA memo summarizing the range adopted by various suppliers, citing a minimum of 20-30%.[28] For the proposed limit of 0.010 lbs/MBtu, the minimum of 20% is used as a design target for ESP upgrades. Thus, the Industry Study applied ESP upgrade and fabric filter O&M enhancements to attain 0.008 lbs/MBtu, in lieu of EPA's target of 0.010 lbs/MBtu. It should be noted this 20% margin is the least of those considered; if the highest operating margin of 50% suggested by EPA in the record of this rule was used the units requiring upgrade and the cost would have been even higher.

As noted by EPA, the sole reliable compliance means for a 0.006 lbs/MBtu PM rate is a fabric filter. Fabric filters historically exhibit low variability due to their inherent design; thus, the operating margin is slightly relaxed to 0.005 lbs/MBtu. Consequently, the Industry Study assumed ESP-equipped units emitting greater than 0.005 lbs/MBtu will retrofit a fabric filter to insure 0.006 lbs/MBtu is attained. Units with existing fabric filters operating at greater than 0.005 lbs/MBtu will adopt improved operation and maintenance, as previously described.

5.2.2 Cost Effectiveness Results

Revised costs from the Industry Study are projected for the proposed fPM limit of 0.010 lbs/MBtu, and the alternative rate of 0.006 lbs/MBtu. Table 5-4 presents these results.

Proposed Limit: 0.010 lbs/MBtu. Results derived in the Industry Study are reported for all three categories of ESP upgrade in Table 5-1. A total of 26 units are required to upgrade ESPs – 11 deploying *Minor*, 7 deploying *Typical*, and 8 deploying *Major* upgrades.[29] In addition, 11 units equipped with fabric filters are required to enhance O&M activities. The totality of these actions each year incur an operating cost of $169.7 M/yr, and remove 2,523 tons of PM.

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[27] Hutson, 2012 and Parker, 2023.

[28] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. at 1 (discussing mercury); 2 (discussing PM).

[29] The two Colstrip units are equipped with an early generation FGD process which does not include an ESP, thus the concept of an ESP upgrade is irrelevant. Consistent with EPA's assumption, the Colstrip units are assumed to retrofit a fabric filter as the only option to meet a limit of 0.010 lbs/MBtu.

Table 5-3. Summary of Results: Industry Study

Technology (Units Affected)	Annual Cost ($M/y)	Tons fPM Removed	$/ton fPM average	Non-Hg metallic HAPS Removed (tons)	$/ton non-Hg metallic HAP ($000s)
Target: 0.010 lbs/MBtu					
ESP Minor (11)	20.9	100	209,340	0.31	67,470
ESP Typical (7)	34.7	282	122,926	0.86	40,216
ESP Major † (8)	113.6	1,665	68,228	5.1	21,662
FF O&M (11)	0.4	475	869	1.45	284
Total or Average	169.7	2,523	67.3	7.71	22,000
Target: 0.006 lbs/MBtu					
FF O&M (23)	1.23	652	1,887	2.61	617
FF Retrofit (52)	1,955.4	6,269	311,900	25.13	102,000
Total or Average	1,956.6	6,921	282,715	27.74	92,470

† Includes 2 fabric filters retrofit to Colstrip Units 3 and 4. See footnote #23.

The incurred cost per ton varies significantly by ESP upgrade category. For the ESP *Minor* upgrade, the average cost effectiveness is approximately $67,470,000 per ton of non-Hg metal HAP for 0.31 of tons removed ($209,340 per ton of fPM for 100 tons of fPM removed). The cost-effectiveness cost effectiveness for the ESP *Typical* upgrade average $40,216,000 per ton of non-Hg metal HAP for 0.86 tons removed ($122,956 tons of fPM for 282 tons of fPM removed). The *Major* upgrade removes the most non-Hg metal HAP – 5.1 tons – (1,665 tons of fPM) for an average cost effectiveness of $21,662,000 per ton of non-Hg metal HAP ($68,228 per ton of fPM). The most cost-effective control evaluated is enhanced fabric filter O&M, which removes 1.45 tons of non-Hg metal HAP at a cost-effectiveness of $284,230/ton (475 tons of fPM at a cost-effectiveness of $869/ton).

These actions cumulatively remove a total of 2,523 tons of PM for an average cost effectiveness of 22,000,000 per ton of non-Hg metal HAP ($67,262 per ton of fPM) removed, a 50% increase compared to the cost estimated by EPA.

Appendix Table A-1 reports the units to which the Industry Study assigned ESP upgrades, and defines the category of upgrade to meet the proposed fPM limit of 0.010 lbs/MBtu.

Possible Lower Limit: 0.006 lbs/MBtu. The Industry Study projects 52 ESP-equipped units would be required to retrofit a fabric filter, removing 25.13 tons of non-Hg metal HAP (6,269 tons of fPM) for an average cost effectiveness of $102,000,000 per ton of non-Hg metal HAP ($311,900 per ton of fPM). In addition, 23 existing units equipped with fabric filters would have to adopt enhanced O&M, removing an additional 2.61 tons of non-Hg metal HAP (652 tons of fPM) for an average of cost of $617,195/ton of non-Hg metal HAP ($1,887/ton of fPM). These actions cumulatively remove a total of 27.74 tons of non-Hg metal HAP (6,921 tons of fPM) for an average cost effectiveness of $92,470,000/ton non-Hg metal HAP ($282,715/ton of fPM) removed. These costs are a factor of almost three times that projected by EPA.

Appendix Table A-2 reports the units to which the Industry Study assigned fabric filter retrofits and enhancements of operating and maintenance procedures, to meet the alternative fPM limit of 0.006 lbs/MBtu.

5.3 Conclusions

- EPA's cost study is deficient in terms of the number of ESP-equipped units required to retrofit improvements, the capital cost assigned for the most significant *Major* ESP improvement, and estimates of $/ton cost-effectiveness incurred. EPA, by ignoring the need for a design and operating margin cited in at least two of their publications (Hutson, 2012 and Parker, 2023) under-predicts the number of units that would require retrofits.

- This study – using the minimum margin cited by EPA in previous publications – projects a much higher annual cost for capital equipment to meet the proposed 0.010 lbs/MBtu - $169.7 M versus EPA's maximum estimate of $93.3 M. To meet the alternative PM rate of 0.006 lbs/MBtu, this study projects 50% more units (87 versus 65) must be retrofit with fabric filters or implement enhanced O&M to an existing fabric filter, incurring an annual cost of $1.96 B versus EPA's estimate of 633 M/yr – a three-fold increase.

- As a consequence, this study predicts the cost effectiveness to meet 0.010 lbs/MBtu will average $22,000,000 per ton of non-Hg metal HAP removed ($67,262 per ton of fPM), a 50% premium to EPA's estimate of $12,200,000 - $14,700,000/ton of non-Hg metal HAP ($37,300 – $44,900/ton of fPM) removed. This study projects the cost to meet the alternative rate of 0.006 lbs/MBtu will average $92,470,000/ton non-Hg metal HAP ($282,715/ton fPM) removed, almost a factor of three higher than EPA's estimate of $103,000/ton.

6. Mercury Emissions: Lignite Coals

Section 6 addresses EPA's proposed action to reduce the limit for Hg for lignite-fired units to 1.2 lbs/TBtu. (the following Section 7 addresses EPA's proposal to retain the present emission limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals (i.e., non-low rank fuels).) This section critiques EPA's basis for proposing the lignite Hg emission rate of 1.2 lbs/MBtu, while supporting the proposal to retain the existing rate for non-low rank coals.

EPA states the following in support of their proposal regarding lignite:

"…..ash from lignite and subbituminous coals tends to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. The natural alkalinity of the subbituminous and lignite fly ash can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0.

Both lignite and subbituminous coal do contain less sulfur than bituminous coal, but other major differences in composition exist that EPA does not recognize. These are Hg content and its variability, the sulfur content, and the alkalinity of inorganic matter. EPA's failure to recognize these differences manifests itself as (a) assuming activated carbon sorbent effectiveness observed on subbituminous coal (specifically PRB) extends to lignite, and (b) ignoring variability in Hg content, as well as the role of sulfur trioxide (SO_3), which compromises achieving 90%+ Hg removal as required to attain 1.2 lbs/TBtu.

Fuel properties are described separately for the North Dakota and Gulf Coast (Texas and Mississippi) lignite mines.

6.1 North Dakota Mines and Generating Units

Figures 6-1 to 6-4 present data provided by lignite suppliers from North Dakota mines that describe the variability for Hg and other constituents key to Hg removal. These figures present data as a "box and whisker" plot, which portrays the mean value, the 25th and 75th percentile of the observed data, and the near-minimum (5%) and near-maximum (95%) extremities. Figure 6-1 shows the variability of Hg and Figure 6-2 the variability of sulfur content. Figure 6-3 shows variability of fuel alkalinity compared to sulfur content – specifically, the ratio of calcium (Ca) and sodium (Na) to sulfur – i.e., the (Ca + Na)/S metric.

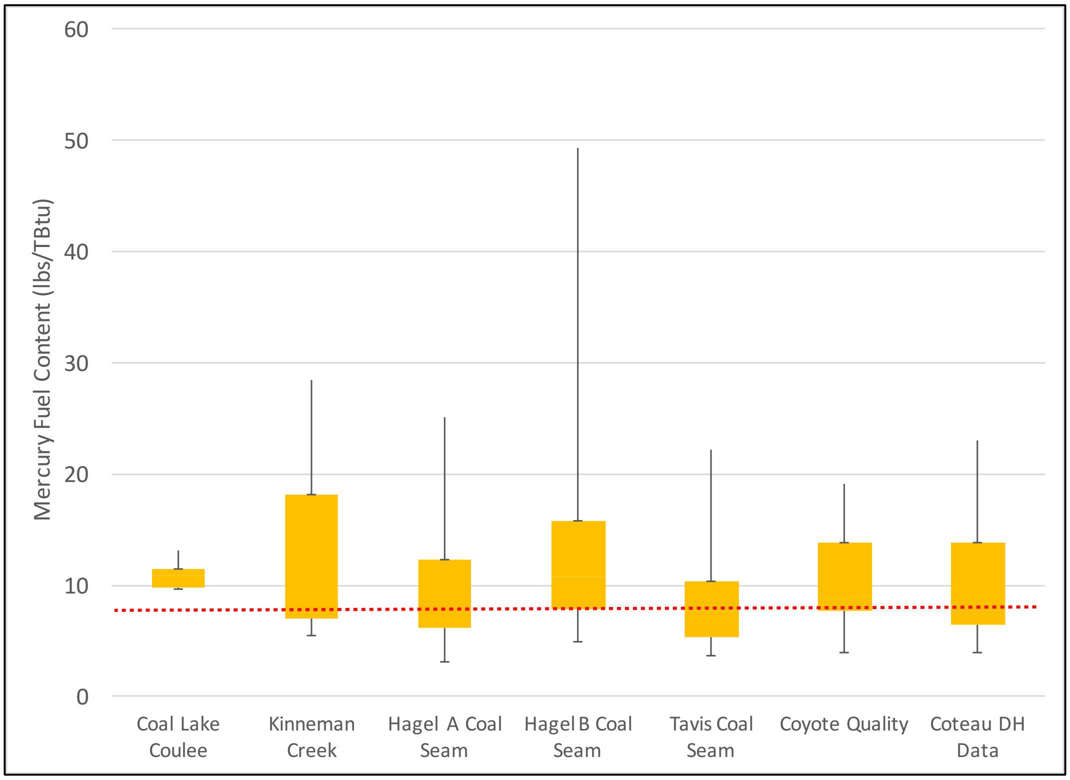

Figure 6-1. Mercury Content Variability for Eight North Dakota Lignite Mines

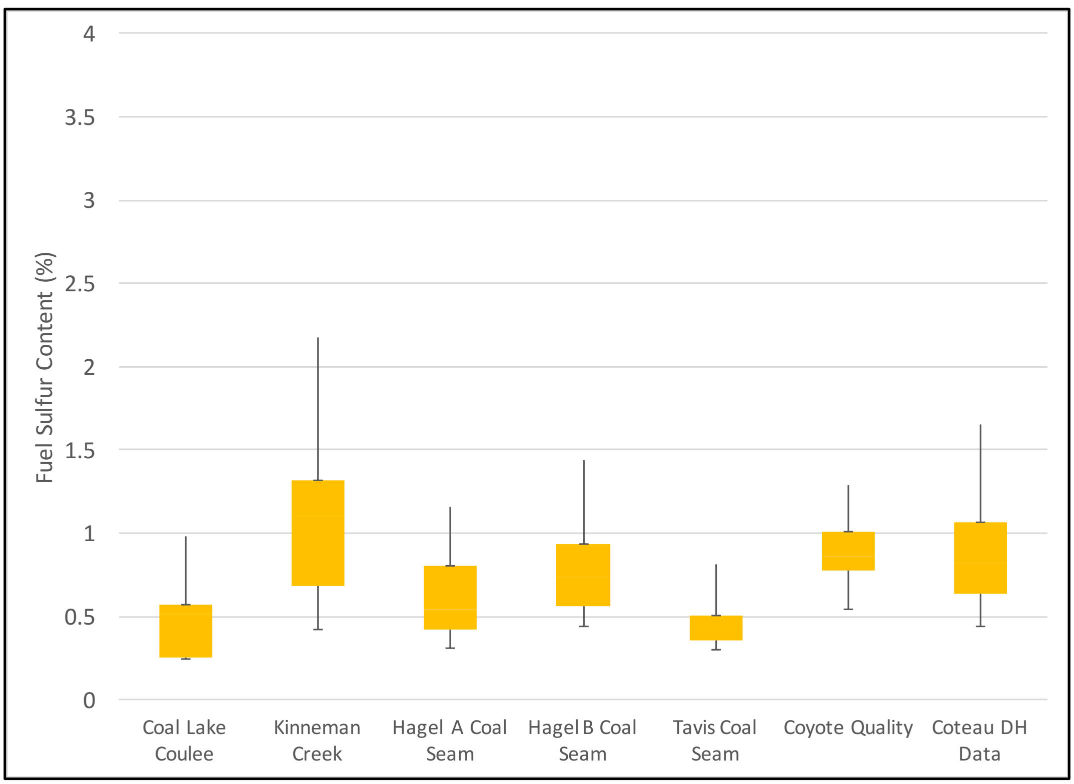

Figure 6-2. Fuel Sulfur Content Variability for Eight North Dakota Lignite Mines

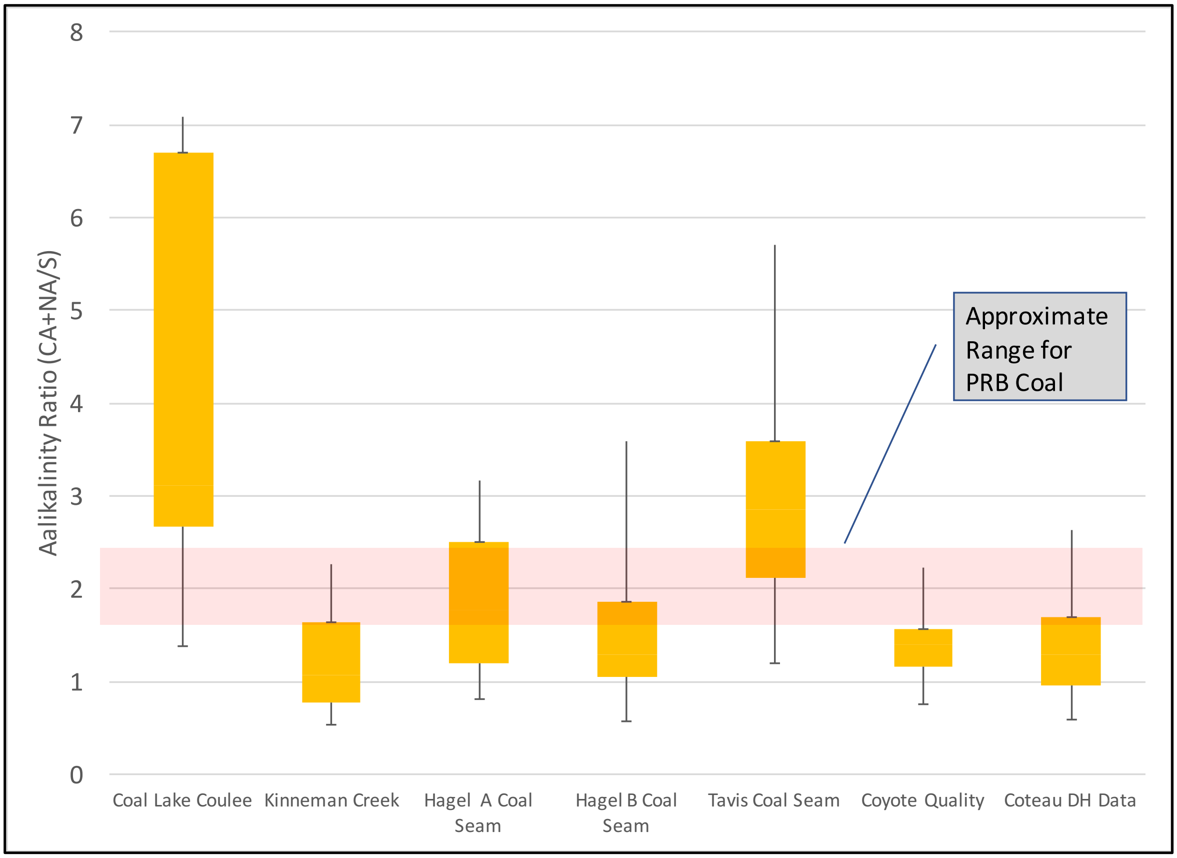

Figure 6-3. Fuel Alkalinity/Sulfur Ratio for Eight North Dakota Mines

Figure 6-1 compares the Hg content and variability to the fixed value of 7.7-7.8 lbs/TBu, assumed by EPA as representing North Dakota lignite, as summarized in Table 11 of the Tech Memo. Figure 6-1 shows – with the exception of the Tavis seam – all mean values of Hg content exceed EPA's assumed value that serves as the basis of EPA's evaluation. More notably, the 75th percentile value of Hg for each seam - slightly more than one standard deviation variance from the mean – in all cases significantly exceeds the value assumed by EPA.

Of note is that the variability of Hg depicted in Figure 6-1 is not necessarily observed only over extended periods of time – such as months or quarters – it can be witnessed over period of days or weeks. This is attributable to the sharp contrast in Hg content of seams that are geographically proximate and thus are mined within an abbreviated time period. Figure 6-4 presents a physical map showing the location of "boreholes" in a lignite field with imbedded text describing (in addition to the borehole code) the Hg content as ppm. The text boxes report this Hg content in terms of lbs/TBtu. These example boreholes – separated by typically 660 feet- and the factor of 3 to 6 variation of Hg content present a meaningful visualization of Hg variability in a lignite mine, and the consequences for the delivered fuel.

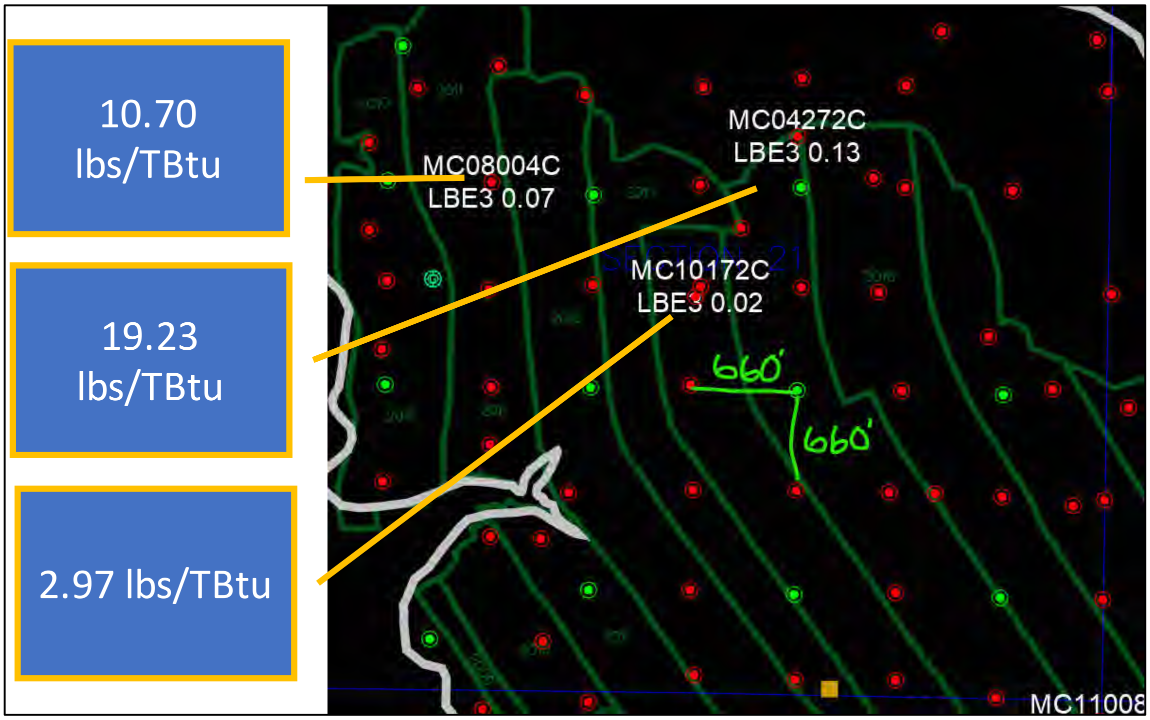

Figure 6-4. Spatial Variation of Hg in a Lignite Mine

Data from Figure 6-1 is summarized in Table 6-1 for units at four stations in North Dakota – Coal Creek, Antelope Valley, Coyote, and Leland Olds. Both Figures 6-1 and Table 6-1 show Hg variability exceed that assumed by EPA in their evaluation. Table 6-1 shows that achieving a 1.2 lbs/TBu requires an Hg removal rate of approximately 93-95% for unavoidable instances where coal Hg content is at the 95th percentile of observed value. The approximate 93-95% Hg removal requirements well exceed the 85% Hg removal based on the IPM-assigned Hg content.

Table 6-1. Hg Variability for Select North Dakota Reference Stations

Station	Mine	Seams	IPM Designated Hg Rate (lbs/TBtu)	Inferred EIA 2021 Hg Rate (lbs/TBtu)	Hg Fuel Content at 95th Percentile (lbs/TBtu)	Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile
Coal Creek	Falkirk	UTAV, HGB1 and HGA1/HGA2 (Mostly Haga A seam)	7.81	7.80	25.1	95.2
Antelope Valley	Freedom	Freedom Mine Belauh Seam	7.81	7.76	23.0	94.8
Coyote	Coyote Creek	Coyote Upper Belauh	7.81	7.79	19.2	93.8
Leland Olds	Freedom	Kinneman Creek, Hagel A, Hagel B	7.81	7.79	23.0	94.8

6.2 Texas Gulf Coast Mines and Generating Units

Figures 6-5 to 6-7 present data from Texas and Mississippi lignite mines describing the content and variability for Hg, sulfur, and the (Ca + Na)/S metric, as delivered to generating units in Texas. Analogous to the data cited for North Dakota, the "box and whisker" depiction represents the same metrics.

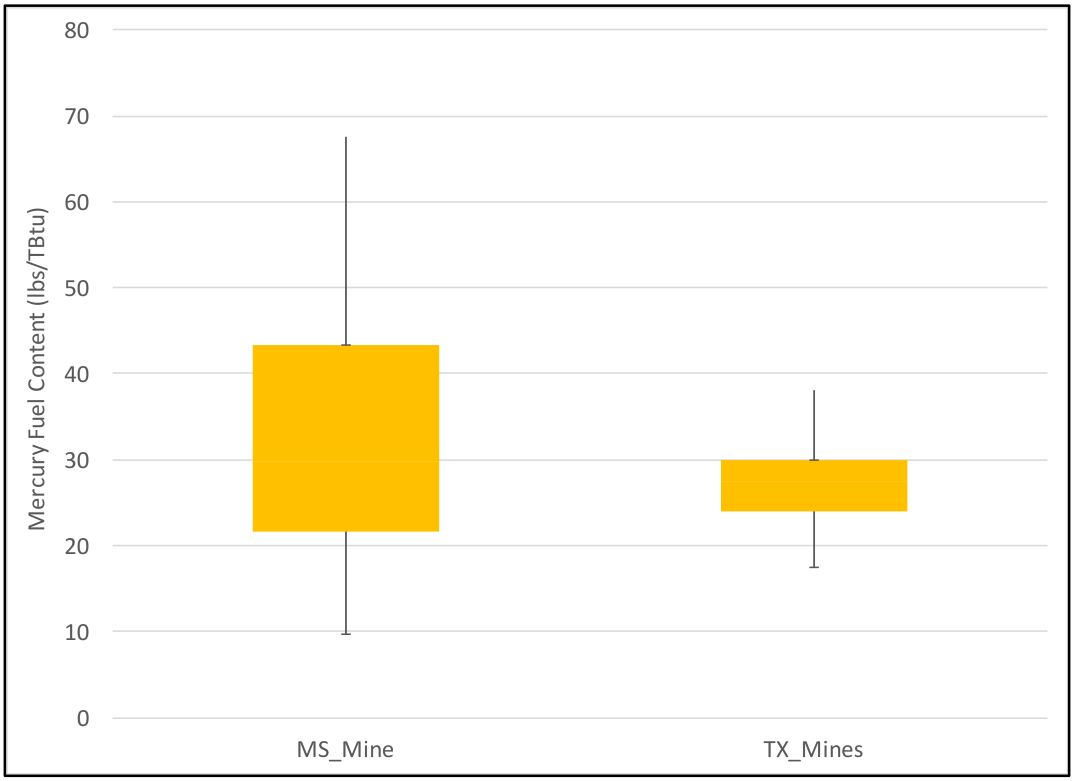

Figure 6-5. Mercury Variability for Two Gulf Coast Sources: Mississippi, Texas

Table 6-2 compares the Hg removal required to meet the proposed 1.2 lbs/TBtu rate considering the variability of Hg in Texas and Mississippi coals, instead of the IPM-assigned Hg coal content. For three Texas plants that fired 100% lignite – Major Oak Units 1 and 2, Oak Grove Units 1 and 2, and San Miguel – EPA assigned inlet Hg values from 12.44 to 14.88 lbs/TBtu, implying Hg removal of 90-92% to achieve 1.2 lbs/TBtu. However, based on the 95th percentile value of the Texas lignite Hg values from Figure 6-5, the required Hg removal would be 96-97%.

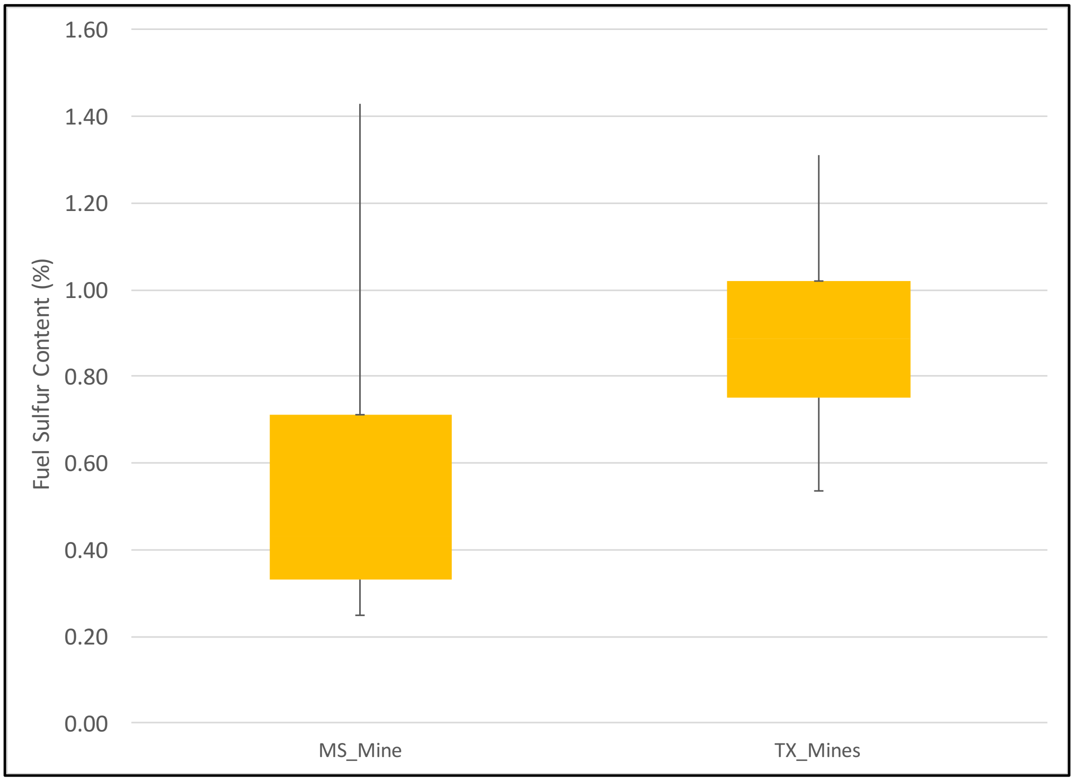

Figure 6-6. Sulfur Variability for Mississippi, Texas Lignite Mines19.1

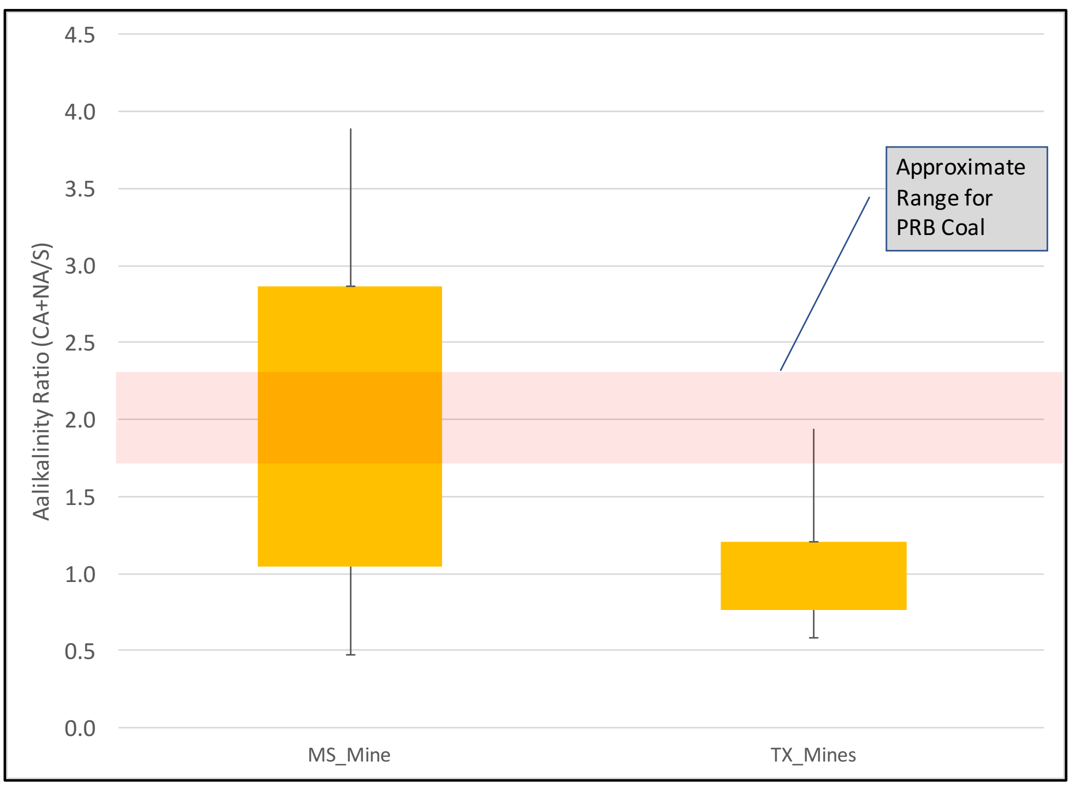

Figure 6-7. Fuel Alkalinity/Sulfur Ratio for Mississippi, Texas Lignite Mines

Table 6-2. Hg Variability for Select Texas Reference Stations

Station	Mines	IPM Designated Hg Rate (lbs/TBtu)	Inferred EIA 2021 Hg Rate (lbs/TBtu)	Hg Fuel Content at 95th Percentile (lbs/TBtu)	Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile
Major Oak 1,2	Calvert	14.65	14.62	38.12	96.9
Oak Grove 1, 2	Kosse Strip	14.88	14.6	38.12	96.9
Red Hills 1, 2	Red Hills	12.44	12.4	67.6	98.2
San Miguel	San Miguel Lignite	14.65	14.62	38.1	96.9

6.3 Role of Flue Gas SO3

EPA equates PRB and lignite coal in terms of constituents that affect Hg capture by carbon sorbent. Data from North Dakota and Gulf Coast mines, displayed in the previous Figures 6-1 to 6-7, show these fuels also contain higher sulfur content than PRB - by a factor or two or more. This relationship is verified by data acquired from EIA Form 960, as provided by power station owners. These fuel data, combined with inherent alkalinity, identifies the problematic role of flue gas SO_3 content.

6.3.1 EIA Hg-Sulfur Relationship

Figure 6-8 compares the seam-by-seam Hg and sulfur content from various power stations firing lignite coals, representing approximately 60 lignite mines and 40 PRB mines. Figure 6-8 shows, even excluding the outlier values of Hg (approximating 50 lbs/TBtu), lignite presents significantly greater variability in Hg and sulfur than PRB. Moreover, lignite coals have a much higher sulfur content than PRB and in many instances have twice the Hg content. The higher sulfur content of lignite equates to greater production rates of sulfur SO_3.

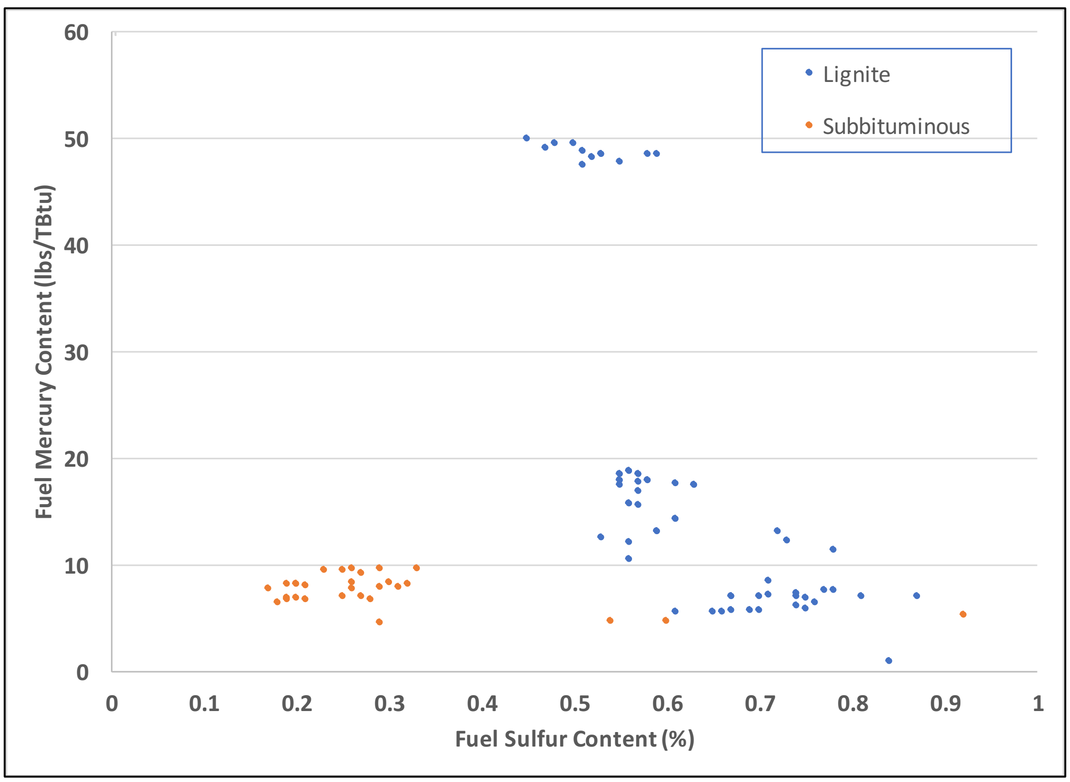

Figure 6-8. Lignite Hg and Sulfur Content Variability: 2021 EIA Submission

An additional factor is the amount of "inherent" alkalinity compared to sulfur – with higher value surpassing the SO_3 content in flue gas. As introduced previously, one metric of this feature is the ratio of Na and Ca to sulfur – on a mole basis.

Figures 6-3 and 6-7 show North Dakota and Gulf Coast lignite present a similar ratio of alkalinity to sulfur content as does PRB – approximating a value of 2. By this metric, lignite fuels in Figure 6-3 present similar means to "buffer" SO_3 as PRB. Notably, Texas lignite in Figure 6-7 is disadvantaged in this metric as the alkalinity to sulfur ratio is half that of PRB – reducing the buffering" effect of inherent ash.

Consequently, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows measurable levels of SO_3 in lignite-generated flue gas, as evidenced by field measurements. EPA does not recognize this distinguishing difference, and states the following regarding lignite and subbituminous coal:[30]

As mentioned earlier, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu with measured values as low as 0.1 lb/TBtu. Clearly EGUs firing subbituminous coal have found control options to demonstrate compliance with the 1.2 lb/TBtu emission standard despite the challenges presented by the low natural halogen content of the coal and production of difficult-to-control elemental Hg vapor in the flue gas stream.

This passage contains two major flaws – that the effectiveness of Hg removal techniques with PRB-generated flue gas can be replicated with lignite, and that average annual Hg emission rates are the metric for comparison. EPA fails to recognize that Hg removal in PRB is in the presence of very little (essentially unmeasurable) SO_3, and 30-day rolling averages exhibit variability not captured by the annual average.

6.3.2 SO_3: Inhibitor to Hg Removal

The ability of SO_3 to interfere with sorbent Hg removal is well-known.[31] Most notably, EPA's contractor for the technology assessments used in the IPM[32] – Sargent & Lundy –for EPA issued assessment on Hg control technology. This document states[33]

With flue gas SO3 concentrations greater than 5 - 7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.

This passage from the S&L technology assessment – funded by EPA to support the IPM model - describes that Hg absorption capacity of carbon can be cut in half by an increase in SO_3 from 5 to 10 ppm. In addition, the presence of SO_3 asserts a secondary role in terms of gas temperature – units with measurable SO_3 are designed with higher gas temperature at the air heater exit – typically where sorbent is injected – to avoid corrosion. Special-purpose tests on a fabric filter

[30] Tech Memo page 21
[31] Sjostrom 2019. See graphics 21-25
[32] Documentation for EPA's Power Sector Modeling Platform v6: Using the Integrated Planning Model, May 2018.
[33] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[34] The role of SO_3 is not considered in assumed carbon injection rates for EPA's economic analysis in Tables 12 and 13 of the Tech Memo.

Publicly available field test data demonstrate the role of SO_3 on carbon sorbent effectiveness. Figure 6-9 presents results from a lignite-fired plant describing Hg removal across the ESP with sorbent injection.[35] This 900 MW unit is reported to fire a higher sulfur lignite in which more than 20 ppm of SO_3 in flue gas is observed preceding the air heater, subsequently decreasing to 10 ppm SO_3 existing the air heater.

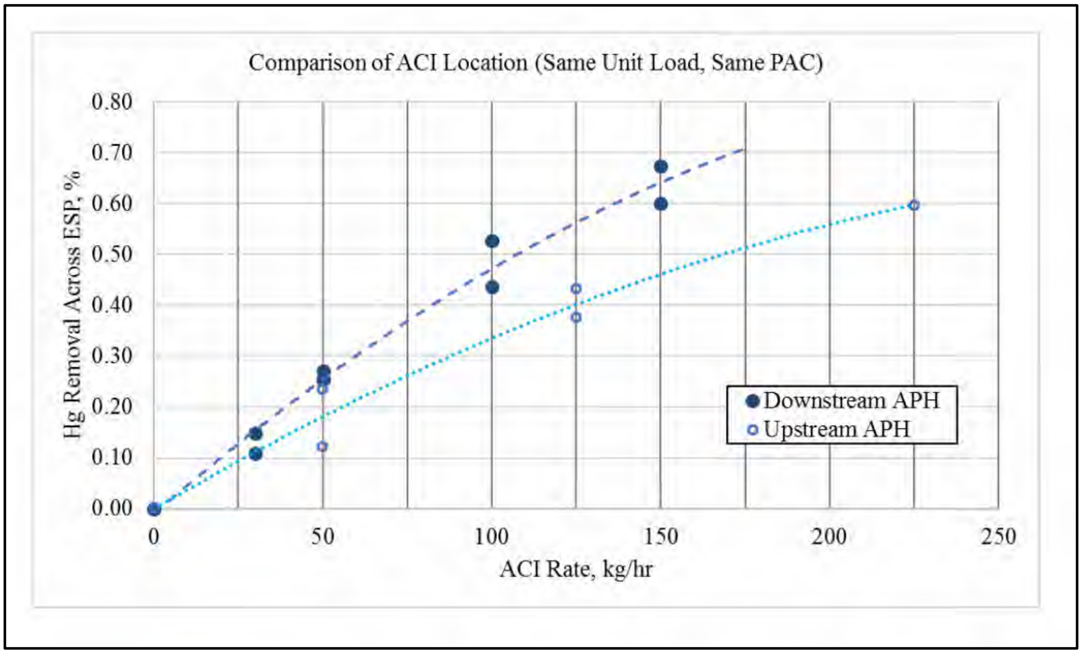

Figure 6-9. Sorbent Hg Removal in ESP in Lignite-Fired Unit: Effect of Injection Location

Data in Figure 6-9 show the role of SO_3 in compromising sorbent performance - highest Hg removal is attained with lower SO_3 (downstream APH) with 60-68% Hg removal achieved (at an injection rate corresponding to 0.6 lbs/MACF).

Attaining a total system 92% Hg removal – the target as described by EPA – is likely not achievable given the trajectory of the curves as shown in Figure 6-9.

6.4 EPA Cost Calculations Ignore FGD

EPA ignores the major role of wet or dry FGD in removing Hg – a fundamental flaw in their analysis. EPA's premise that sorbent addition is the sole compliance technology is incorrect – 18 of 22 units in the lignite fleet listed in Table 9 of the RTR Tech Memo are equipped with FGD.

[34] Sjostrom 2016. See graphic 16.

[35] Satterfield, J., Optimizing ACI Usage to Reduce Costs, Increase Fly Ash Quality, and Avoid Corrosion, presentation to the Powerplant Pollutant and Effluent Control Mega Symposium, August, 2018.

Of these 18 units, 4 are equipped with dry FGD and 14 with wet FGD. This process equipment asserts a major role in Hg removal as discussed in the next section.

The calculation of cost-effectiveness for the model plant as presented in Section (e)(i) of the RTR Tech memo addresses only sorbent addition, thus does not reflect the Hg compliance strategy of 18 units in the lignite fleet. EPA assumes (a) upgrade of sorbent from "conventional" activated carbon to the halogenated form, and (b) increasing sorbent injection from 2.5 to 5.0 lbs/MAFH elevates Hg reduction from 73% to 92%.[36] This assumption is not relevant – at least in this specific form – to 18 of 22 units in the lignite fleet, as wet or dry FGD will contribute to Hg removal. EPA's approach could underestimate the cost per ton incurred, as tons of Hg removed by the FGD could be credited to sorbent injection (the denominator of the $/ton calculation is larger than it should be).

The variable of FGD Hg removal cannot be ignored, and undermines the legitimacy of the cost estimates as Hg removed by FGD cannot be ascribed to sorbent injection. Thus, depending on how or if the sorbent injection rate changes, costs could increase beyond EPA's estimate (as the denominator in the $/ton calculation is reduced.

6.5 Conclusions

- EPA's proposal that Hg emissions of 1.2 lbs/TBtu can be attained for lignite-fired units by increasing sorbent injection rate and adding halogens (to compensate for loss of refined coal) is incorrect, as it assumes sorbent injection Hg removal observed with PRB is achievable on lignite.

- Flue gas generated from lignite exhibits measurable SO_3 in quantities that– as summarized by EPA's contractor for IPM model inputs - reduce the effectiveness of sorbent by 50% and in some cases presents a barrier to 90% Hg removal.

- Accounting for the variability of Hg content in lignite for most North Dakota and Texas lignite fuels, more than 90% Hg removal is required to meet 1.2 lbs/MBtu, exceeding the nominally 80% removal estimated by EPA, and over a 30-day rolling average basis is unlikely to be attained.

- EPA's calculation of cost–effectiveness for lignite fuels ignores the role of FGD, present in 18 of the 22 reference stations, in removing Hg. The result of this erroneous assumption could be an under-estimation of the cost for additional Hg removal.

[36] EPA uses the incorrect constant in the calculation of gas flow rate to translate sorbent injection from a mass per time basis (lb//hr) to mass per unit volume of gas (lbs/MACF). The calculation on page 24 uses the value of 9,860 scf/MBtu to quantify flue gas generated from lignite coal. Per EPA-454/R-95-015 (Procedure for Preparing Emission Factor Documents, OAQPS, November 1997) this value reflects the dry volume of gas produced from lignite coal, per MBtu. The flue gas rate that is processed by the environmental controls is the authentic "wet" basis and about 20% higher per MBtu (12,000 scf/MBtu). Use of the correct, latter constant lowers the value of sorbent per MACF by the same magnitude.

7. Mercury Emissions: Non-Low Rank Fuels

Section 7 addresses EPA's proposal to retain the present Hg limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals.

EPA recognizes that Hg emission rates - as determined on an annual average basis - have decreased significantly since the initial MATS rule was issued, with bituminous–fired units averaging 0.4 lbs/TBtu (and ranging between 0.2 and 1.2 lbs/TBtu) and subbituminous-fired units averaging 0.6 lbs/TBtu (ranging between 0.1 to 1.2 lbs/TBtu).[37] EPA states these Hg emission rates represent between a 77 and 98% Hg removal from an assumed Hg inlet value of 5.5 lbs/TBtu. EPA notes they did not acquire detailed information on compliance steps such as the type of sorbent injected, the rate of sorbent injection, and the role of SCR NOx control and wet FGD and the myriad factors that determine Hg removal "co-benefits."

This section addresses the reported Hg removal and basis for EPA's position.

7.1 Hg Removal

EPA's discussion of the annual average of Hg removal does not consider the 30-day rolling average, the more challenging metric to attain – and the metric mandated for compliance. The 30-day rolling average reflects variability in Hg coal content and process conditions, both of which can experience daily or hourly changes, which obviously is not captured in annual averages.

Figures 7-1 and 7-2 report two metrics of Hg emission rate variability.[38] Figure 7-1 presents the mean and standard deviation of Hg annual average emissions for eleven categories of control technology and fuel rank. For six of these eleven categories, the sum of the mean and the standard deviation approach the Hg limit of 1.2 lbs/TBtu.

Figure 7-2 describes for six categories of control technology and 2 or 3 fuel ranks (depending on the technology) the number of units that for at least one operating day exceed 1.2 lbs/TBtu on a 30-day rolling average. Figure 7-2 shows for all categories of control technology and fuel rank experience 10% to 20% of units exceed this 30-day average.

In summary, EPA's report of annual Hg emission rate - significantly reduced compared from 2012 – does not provide a basis for further reductions as annual data does not account for variability.

[37] Prepublication Version, page 85

[38] Cichanowicz, J. E. et. al., Mercury Emissions Rate: The Evolution of Control Technology Effectiveness, Presented at the Power Plant Pollutant and Effluent Control MEGA Symposium: Best Practices and Trends, August 20-23, 2018, Baltimore, MD.

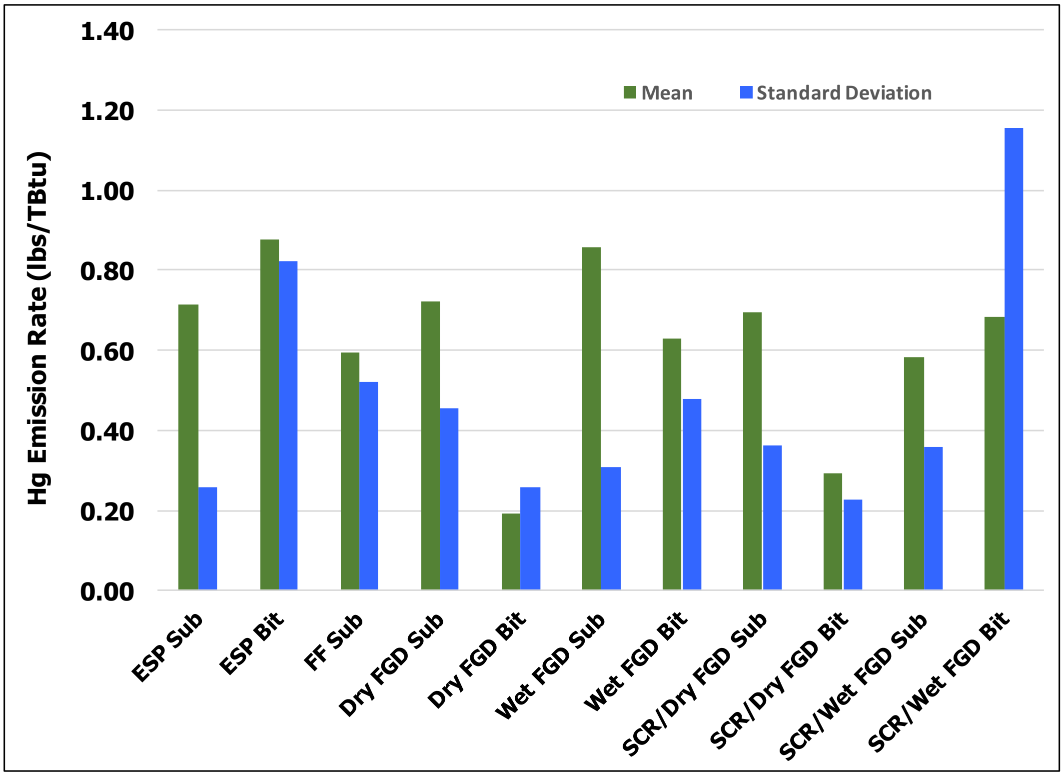

Figure 7-1. Mean, Standard Deviation of Annual Hg Emissions: 2018

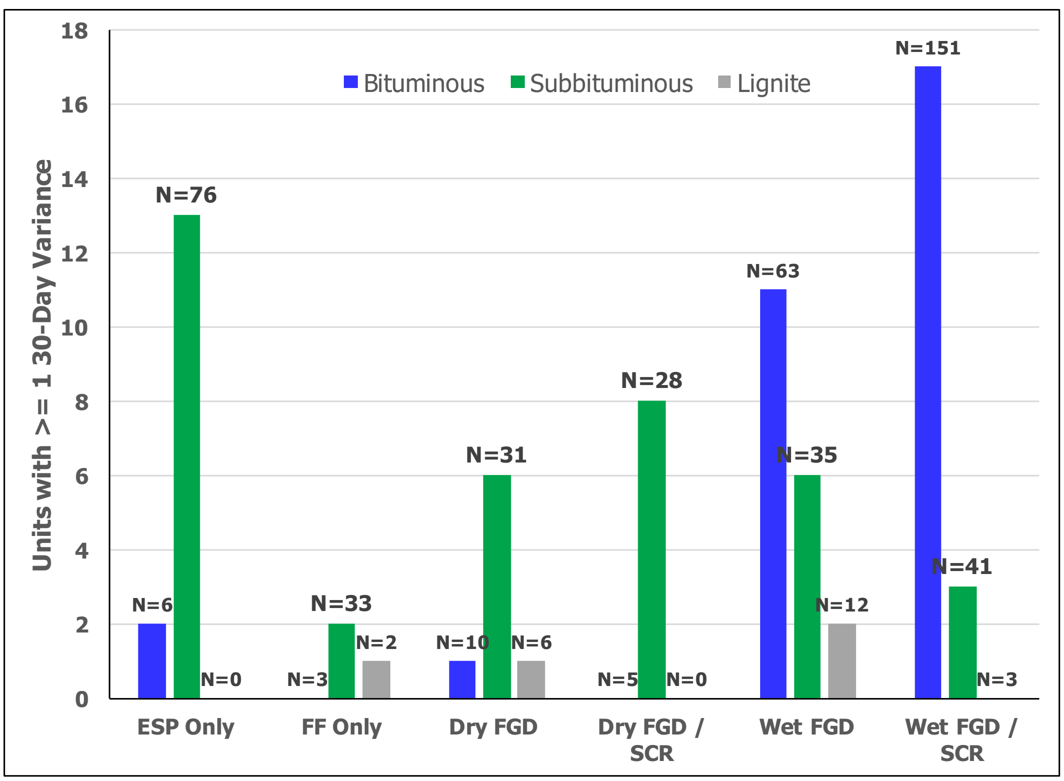

Figure 7-2. Mean, Standard Deviation of Annual Hg Emissions: 2018

7.2 Role of Fuel Composition and Process Conditions

Hg emissions are defined by variability in coal composition and process conditions, the latter including sorbent type, and injection rate, and the "co-benefit" Hg removal imparted by SCR NOx control and wet or dry FGD.

Although EPA did not elicit detailed process information from owners via Section 114, several key insights are presented in a 2018 survey conducted by ADA.[39]

7.2.1 Coal Variability

EPA cites observing for Hg emissions "a control range of 98 to 77 percent (assuming an average inlet concentration of 5.5 lb/TBtu)."[40] It is not clear if EPA assigns the average Hg content value of 5.5 lbs/TBtu to both bituminous and subbituminous coal, or solely the latter.

Figure 7-3 shows an average value of 5.5 lbs/TBtu does not represent either coal rank well. Figure 7-3 presents – on an annual average basis – data from more than 70 units reporting Hg content to the EIA. Numerous units report up to 10 lbs/TBtu - almost twice the average value EPA assigns, with 10 additional units reporting Hg content exceeding 10 lbs/TBtu. Northern Appalachian bituminous coals appear to contain higher Hg content than coals from other regions.

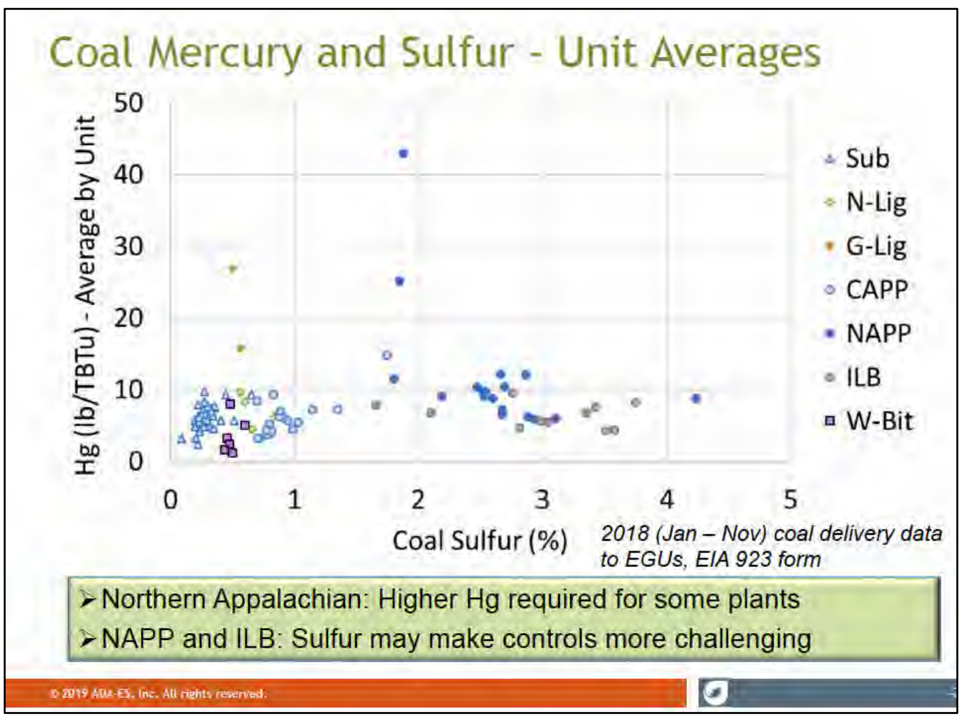

Figure 7-3. Annual Average of Fuel Hg, Sulfur Content in Coal

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[39] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review

[40] RTR Tech Memo, page 19.

Consequently, EPA's calculation of 98 to 77% Hg removal is likely inaccurate as the assumed coal Hg content is too low.

7.2.2 Process Conditions

The process conditions for Hg removal: sorbent composition, sorbent injection rate, and the "co-benefits" of SCR NOx control and wet FGD are highly variable, due to a combination of factors. The following provides several examples.

Refined Coal. The absence of Refined Coal – no longer a viable option - complicates projecting future Hg emissions. A survey of Hg compliance activities for 2018 reported Refined Coal as a compliance step;[41] EIA fuel records show this trend persisted through 2021. EPA's assumption that adding halogens to the fuel or flue gas compensates for the unavailability of Refined Coal is speculative and without basis. *Without assurances of the benefits from the halogen content of Refined Coal, it is not possible to assess the viability of lowering Hg emissions.*

Sorbent Injection. Sorbent injection is a key compliance step for 70% of subbituminous-fired units, for some augmented with coal additives and Refined Coal. For bituminous-fired units, 18% of coal use is treated by some combination of sorbent injection and coal additives.

As described by EPA, increasing the rate of sorbent injection increases Hg removal – but with diminishing returns as sorbent mass is added. An example of this relationship is provided by full-scale tests at Ameren's PRB-fired Labadie Unit 3. These tests explored the effectiveness of both conventional and brominated activated carbon. These tests, purposely conducted in PRB-generated flue gas to define sorbent performance in the absence of SO_3, show Hg removal of 90% or more is feasible and that halogen addition can lower sorbent rate.[42]

This relationship is complicated by the role of Refined Coal, coal additives, and (as described below) the contribution of "co-benefits". *Devising a reasoned prediction of Hg removal under variable conditions, including coal composition and the impact of changing sorbents is not possible with current available information.*

SCR, FGD Co-Benefits. The capture of Hg by wet FGD – in many cases prompted by the role of SCR catalysts to oxidize elemental Hg – can be a primary mean for Hg capture. However, such co-benefits are highly variable, and depend on the ratio of elemental to oxidized Hg in the flue gas, and the consequential Hg "re-emission" by a wet FGD. There are means to remedy this variability in some instances, but broad success cannot be assured. *Without the specifics of FGD design and operation, Hg removal via wet FGD cannot be predicted.*

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[41] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review. Hereafter Sjostrom 2019.

[42] Senior, C. et. al., *Reducing Operating Costs and Risks of Hg Control with Fuel Additives*, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.

Hg Re-Emission. The fate of Hg entering a wet FGD is uncertain.[43] If in the oxidized state, Hg upon entering the FGD solution can (a) remain in solution and be discharged with the FGD-cleansing step of "blowdown" (b) precipitate as a solid and be removed with the byproduct (typically gypsum), or (c) be reduced from the oxidized to the elemental state, thus re-emitted in the flue gas. Several means to minimize Hg re-emission exist, including injection of sulfite and controlling the scrubber liquor oxidation/reduction potential (ORP). These means can limit Hg remission but are additional process steps that are superimposed upon the task of achieving high efficiency SO_2 removal. *The extent these means can be universally applied without compromising SO_2 removal is uncertain.*

Role of Variability Due to Load Changes. An in-plant study showed that increasing load for a wet FGD-equipped unit can elevate Hg re-emission, eventually exceeding 1.2 lbs/TBtu.[44] This observation can be due to loss of the control over the ORP, defined in the previous paragraph as a key factor in FGD Hg removal. Chemical additives can adjust ORP but complete and autonomous control may not be available. For example, in a systematic evaluation of FGD operating variables conducted at a commercial power station, factors such as limestone composition and the extent to which units must operate in zero-water discharge – as perhaps mandated by the pending Effluent Limitation Guideline – can affect ORP and thus Hg-re-emission.[45]

Upsets in wet FGD process conditions can prompt Hg re-emission. Specifically, one observer noted two units that "….experienced a scrubber reemission event causing the mercury stack emissions to increase dramatically above the MATS limit and significantly higher than the incoming mercury in the coal and the event lasting for several days."[46] This high Hg event was eventually remedied over the short-term operation, but long-term performance is not available.

7.3 Conclusions: Mercury Emissions - Non-Low Rank Coals

There is inadequate basis to further lower the Hg emissions rate below the present limit of 1.2 lbs/TBtu, as variability in fuel and process operations outside the control of the operator can elevate emissions to approach or in some cases exceed that rate.

[43] Gadgil, M., 20 Years of Mercury Re-emission – What do we Know?, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.
[44] Blythe, G. et. al., Maximizing Co-Benefit Mercury Capture for MATS Compliance on Multiple Coal-Fired Units, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[45] Blyte, G. et. al., Investigation of Toxics Control by Wet FGD Systems, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[46] Pavlisch, J. et. al., Managing Mercury Reemission and Managing MATS compliance Using a sorbent Approach, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.

8. EPA IPM RESULTS: EVALUATION AND CRITIQUE

EPA used the Integrated Planning Model (IPM) to establish a Baseline Scenario from which to measure compliance impacts of the proposed rule. This Baseline Scenario is premised upon IPM's Post-IRA 2022 Reference Case. In this Post-IRA simulation, IPM evaluated a number of tax credit provisions of the Inflation Reduction Act of 2022 (IRA), which address application of Carbon Capture and Storage (CCS) and other means to mitigate carbon dioxide (CO_2). These are the (i) New Clean Electricity Production Tax Credit (45Y); (ii) New Clean Electricity Investment Credit (48E); Manufacturing Production Credit (45X); CCS Credit (45Q); Nuclear Production Credit (45U); and Production of Clean Hydrogen (45V). Also, the Post-IRA 2022 Reference Case includes compliance with the proposed Good Neighbor Policy (Transport Rule).[47]

A critique of EPA's methodology and findings is described subsequently.

8.1 IPM 2030 Post-IRA 2022 Reference Case: A Flawed Baseline

The IPM Post-IRA 2022 Reference Case for the years 2028 and 2030 comprises a flawed baseline to measure compliance impacts of the proposed rule. This flawed baseline centers around IPM projected coal retirements in both 2028 and 2030 as well as units projected to deploy CCS in 2030. Specifically, IPM has erroneously retired numerous coal units expected to operate beyond 2028 and 2030 based upon current announced retirement plans; consequently, these units are subject to the proposed rule beginning in 2028. There are numerous challenges and limitations to deploying CCS as EPA has projected on 27 coal units in 2030. These units would also be subject to the proposed. Consequently, IPM's compliance impacts of the proposed rule is likely understated.

8.1.1 Analytical Approach

This analysis identifies those units IPM modeled as coal retirements, CCS retrofits and coal to gas (C2G) conversions in both 2028 and 2030, and compares them to announced plans for unit retirements, technology retrofits and C2G conversions. To identify errors for 2028, the parsed file for the 2028 Post-IRA 2022 Reference Case was used. Since EPA did not provide a parsed

[47] In addition to the IRA and GNP, the Post-IRA 2022 Reference Case takes into account compliance with the following: (i) Revised Cross-State Air Pollution Rule (CSAPR) Update Rule; (ii) Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; (iii) MATS Rule which was finalized in 2011; (iv) Various current and existing state regulations; (v) Current and existing RPS and Current Energy Standards; (vi) Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART); and, (vii) Platform reflects California AB 32 and RGGI. Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

file of the 2030 Post-IRA 2022 Reference Case, an abbreviated parsed file was created using four different IPM files. These are: (i) 2028 parsed file of the Post-IRA 2022 Reference Case; (ii) Post-IRA 2022 Reference Case RPE File for the year 2030; (iii) Post-IRA 2022 Reference Case RPT Capacity Retrofits File for the year 2030; and, (iv) National Electrical Energy Data System (NEEDS) file for the Post-IRA 2022 Reference Case. These parsed files allow identifying IPM modeled retirements in 2028 and 2030, CCS retrofits in 2030 and C2G in both 2028 and 2030. These modeled retirements and conversions were compared to announced information in the James Marchetti Inc ZEEMS Data Base.

8.1.2 Coal Retirements

The 2028 IPM modeling run retired 112 coal units (53.6 GW) from 2023 to 2028. In the 2030 analysis, IPM retired an additional 52 coal units (25.5 GW). The total number of retirements for the two modeling run years is 164 coal units (79.1 GW).

Table 8-1 summarizes the IPM retirement errors in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly retired 29 coal units (14.0 GW) by 2028 and an additional 23 coal units (14.1 GW) in 2030. In addition, there are 3 coal units (1.6 GW) that EPA listed in the NEEDS file as being retired before 2028 that will operate beyond 2030. In total, there are 55 coal units that IPM erroneously retired in the 2028 and 2030 modeling runs that will be operating and subject to some aspect of the proposed rule beginning in 2028.

Table 8-1. Coal Retirement Errors

Year	Description	Number
2028	Retiring after 2028	29
2030	Retiring after 2030	23
2030	NEEDS retirements that should be in the 2030 modeling platform	3
Total		55

Tables 8-2 to 8-6 lists each of the coal units IPM has incorrectly retired, incorrectly deployed CCS, or switched to natural gas.

Table 8-2. IPM Coal Retirement Errors: 2028 Post-IRA 2022 Reference Case Run

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Capacity	Observation
1	WECC_Arizona	Arizona	6177	U1B	Coronado	380	To be retired by 2032 and continued seasonal curtailemts,
2	SPP West	Arkansas	6138	1	Flint Creek	528	Retire January 1, 2039 - Entergy LL 2023 IRP (March 31, 2023).
3	MISO_Arkansas	Arkansas	6641	1	Independence	809	Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030.
4	MISO_Arkansas	Arkansas	6641	2	Independence	842	Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030.
5	SERC_Central_TVA	Kentucky	1379	2	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
6	SERC_Central_TVA	Kentucky	1379	3	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
7	SERC_Central_TVA	Kentucky	1379	5	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
8	SERC_Central_TVA	Kentucky	1379	6	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
9	SERC_Central_TVA	Kentucky	1379	7	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
10	SERC_Central_TVA	Kentucky	1379	8	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
11	SERC_Central_TVA	Kentucky	1379	9	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
12	MISO_Minn/Wisconsin	Minnesota	6090	3	Sherburne County	876	PSC approved closure (2/8/22). Upper Midwest Resource Plan (6/25/21) for 2030.
13	MISO_Missouri	Missouri	2103	1	Labadie	593	2022 IRP Update retire in 2042 (6/24/22).
14	MISO_Missouri	Missouri	2103	2	Labadie	593	2022 IRP Update retire in 2042 (6/24/22).
15	MISO_Missouri	Missouri	2103	3	Labadie	593	2022 IRP Update (6/24/22) retirement in 2036
16	MISO_Missouri	Missouri	2103	4	Labadie	593	2022 IRP Update (6/24/22) retirement in 2036
17	MISO_Missouri	Missouri	2107	1	Sioux	487	2022 IRP Update (6/24/22) - To be retired in 2030
18	MISO_Missouri	Missouri	2107	2	Sioux	487	2022 IRP Update (6/24/22) - To be retired in 2030
19	SERC_VACAR	North Carolina	2712	3A.3B	Roxboro	694	2022 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22).
20	SERC_VACAR	North Carolina	2712	4A, 4B	Roxboro	698	2023 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22).
21	ERCOT_Rest	Texas	298	LIM1	Limestone	831	EIA 860 has retirement December 2029
22	ERCOT_Rest	Texas	298	LIM2	Limestone	858	EIA 860 has retirement December 2029
23	WECC_Utah	Utah	7790	1-1	Bonanza	458	Unit is planned to retire in 2030,
24	WECC_Utah	Utah	8069	2	Huntington	450	Retire in 2032 - 2023 IRP (3/31/23)
25	PJM_Dominion	Virginia	7213	1	Clover	440	Dominion 2023 IRP - Retirement Date 2040 (5/1/23)
26	PJM_Dominion	Virginia	7213	2	Clover	437	Dominion 2023 IRP - Retirement Date 2040 (5/1/23)
27	PJM_AP	West Virginia	3943	1	Fort Martin	552	EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2035
28	PJM_AP	West Virginia	3943	2	Fort Martin	546	EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2036
29	WECC_Wyoming	Wyoming	6101	BW91	Wyodak	332	Retire in 2039 - IRP (3/31/23)

Table 8-3. IPM Coal Retirement Errors: 2030 Post IRA 2022 Reference Case Modeling Run

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Capacity	Observations
1	WECC_Arizona	Arizona	6177	U2B	Coronado	382	To be retired by 2032 and contined seasonal curtailments
2	FRCC	Florida	628	4	Crystal River	712	To be retired in 2034 (2020 Sustainability Report)
3	FRCC	Florida	628	5	Crystal River	710	To be retired in 2034 (2020 Sustainability Report)
4	SERC_Southeastern	Georgia	6257	1	Scherer	860	ELG Compliance - Wastewater Treatment - No Announced Retirement
5	SERC_Southeastern	Georgia	6257	2	Scherer	860	ELG Compliance - Wastewater Treatment - No Announced Retirement
6	PJM West	Indiana	1040	1	Whitewater Valley	35	Biased to peak load duty. 2020 IRP Base Case has retirement May 31, 2034
7	MISO_Iowa	Iowa	1167	9	Muscatine Plant #1	163	ELG compliance options for FGDW and BATW, possible 2028 retirement
8	SPP North	Kansas	6068	1	Jeffrey Energy Center	728	To be retired at the end of 2039 (2021 IRP)
9	SPP North	Kansas	1241	2	La Cygne	662	To be retired at the end of 2039 (2021 IRP)
10	SERC_Central_Kentucky	Kentucky	1356	1	Ghent	474	To be retired 2034
11	SERC_Central_Kentucky	Kentucky	1356	3	Ghent	485	To be retired 2037.
12	SERC_Central_Kentucky	Kentucky	1356	4	Ghent	465	To be retired 2037.
13	SPP North	Missouri	6065	1	Iatan	700	To be retired at the end of 2039 (2021 IRP)
14	SPP North	Missouri	6195	1	John Twitty	184	Beyond 2030 retirement date - new 2022 IRP
15	SERC_VACAR	North Carolina	8042	1	Belews Creek	1110	1/1/2036 retirement per 2022 Carbon Reduction Plan
16	SERC_VACAR	North Carolina	8042	2	Belews Creek	1110	1/1/2036 retirement per 2022 Carbon Reduction Plan
17	SERC_VACAR	North Carolina	2727	3	Marshall (NC)	658	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22)
18	SERC_VACAR	North Carolina	2727	4	Marshall (NC)	660	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22)
19	MISO_MT, SD, ND	North Dakota	8222	B1	Coyote	429	Active perl reliablity concerns in MISO. End of depreciable life - 2041
20	SERC_VACAR	South Carolina	6249	1	Winyah	275	2023 IRP: operate unit through 2030 for reliability (4/19/23)
21	SERC_VACAR	South Carolina	6249	2	Winyah	285	2024 IRP: operate unit through 2030 for reliability (4/19/23)
22	SERC_VACAR	South Carolina	6249	3	Winyah	285	2025 IRP: operate unit through 2030 for reliability (4/19/23)
23	SERC_VACAR	South Carolina	6249	4	Winyah	285	2026 IRP: operate unit through 2030 for reliability (4/19/23)
24	PJM West	West Virginia	3935	1	John E Amos	800	Approved ELG upgrades to keep plant open until 2040.
25	PJM West	West Virginia	3935	2	John E Amos	800	Approved ELG upgrades to keep plant open until 2040.
26	PJM_AP	West Virginia	3954	1	Mt Storm	554	Dominion 2023 IRP - Retirement Date 2044 (5/1/23)
27	PJM_AP	West Virginia	3954	2	Mt Storm	555	Dominion 2023 IRP - Retirement Date 2044 (5/1/23)

Table 8-4 Units in the NEEDS to Be Operating in 2028

No.	Region Name	State Name	ORIS Plant	Unit ID	Plant Name	Capacity (MW)	NEEDS Retirement Year	Observations
1	SPP_N	Kansas	1241	1	La Cygne	736	2025	2022 IRP Update to be retired in 2032
2	MIS_LA	Louisiana	6190	3-1, 3-2	Brame Energy Center	626	2027	No plans to retire. Evaluating CCS
3	WECC_WY	Wyoming	4158	BW44	Dave Johnston	330	2027	Retire in 2039 - 2023 IRP (3/31/23).

Table 8-5 Units IPM Predicts CCS By 2030

No.	Region Name	StateName	ORISCode	UnitID	PlantName	Capacity	Observations
1	ERCOT_Rest	Texas	6179	3	Fayette Power Project	286.05	
2	ERCOT_Rest	Texas	7097	BLR2	J K Spruce	537.93	Board voted to convert to natural gas by 2027 (1/23/23)
3	ERCOT_Rest	Texas	6180	1	Oak Grove (TX)	572.77	
4	ERCOT_Rest	Texas	6180	2	Oak Grove (TX)	570.97	
5	ERCOT_Rest	Texas	6183	SM-1	San Miguel	237.74	
6	FRCC	Florida	645	BB04	Big Bend	292.27	
7	MISO_Indiana	Indiana	6113	1	Gibson	594.24	
8	PJM West	Kentucky	6018	2	East Bend	399.00	
9	PJM West	West Virginia	3948	1	Mitchell (WV)	537.77	
10	PJM West	West Virginia	3948	2	Mitchell (WV)	537.77	
11	SERC_Southeastern	Alabama	6002	4	James H Miller Jr	477.05	
12	SPP_WAUE	North Dakota	6469	B1	Antelope Valley	289.22	
13	SPP_WAUE	North Dakota	6469	B2	Antelope Valley	288.38	
14	SPP_WAUE	North Dakota	2817	2	Leland Olds	279.16	
15	WECC_Arizona	Arizona	8223	3	Springerville	281.05	
16	WECC_Arizona	Arizona	8223	4	Springerville	281.05	
17	WECC_Colorado	Colorado	470	3	Comanche (CO)	501.15	To be retired Dec 31 2030 (10/31/22)
18	WECC_Colorado	Colorado	6021	C3	Craig (CO)	305.66	To be retired Dec 2029 - Electric Resource Plan (12/1/20)
19	WECC_Utah	Utah	6165	1	Hunter	319.80	Retire in 2031- 2023 IRP (3/31/23)
20	WECC_Utah	Utah	6165	2	Hunter	292.44	Retire in 2032 - 2023 IRP (3/31/23).
21	WECC_Utah	Utah	6165	3	Hunter	314.06	Retire in 2032 - 2023 IRP (3/31/23).
22	WECC_Utah	Utah	8069	1	Huntington	311.54	Retire in 2032 - 2023 IRP (3/31/23).
23	WECC_Wyoming	Wyoming	8066	BW73	Jim Bridger	354.02	Convert to natural gas in 2030 - 2023 IRP (3/31/23)
24	WECC_Wyoming	Wyoming	8066	BW74	Jim Bridger	349.78	Convert to natural gas in 2030 - 2023 IRP (3/31/23)
25	WECC_Wyoming	Wyoming	6204	1	Laramie River Station	385.22	
26	WECC_Wyoming	Wyoming	6204	2	Laramie River Station	382.92	
27	WECC_Wyoming	Wyoming	6204	3	Laramie River Station	383.45	

Table 8-6 Units IPM Erroneously Predicts Switch to Natural Gas

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Year	Capacity	Observations
1	SPP West (Oklahoma,	Arkansas	56564	1	John W Turk Jr Power Plant	2030	609	Retire Jan 1, 2068 - SWEPCO 2023 IRP (March 29, 2023)
2	PJM West	Kentucky	6041	2	H L Spurlock	2028	510	No announced C2G or co-firing
3	ERCOT_Rest	Texas	56611	S01	Sandy Creek Energy Station	2030	933	No announced conversion

8.1.3 Coal CCS

Table 8-5 identifies the 27 units IPM projected to retrofit CCS by 2030; none of these have been involved in any Front-End Engineering and Design (FEED) Studies. However, 9 of the units identified by IPM will be either be retired or converted to natural gas in and around 2030. There are major questions addressing infrastructure and project implementation that present challenges to IPM's CCS projection for 2030. Indeed, it is next to impossible for these units to be in position to retrofit CCS by 2030.

8.1.4 Coal to Gas Conversions (C2G)

The 2028 IPM modeling run converted 36 coal units to gas (14.3 GW). In the 2030 IPM modeling run an additional 2 coal units (1.5 GW) were converted to gas (Turk and Sandy Creek). As shown in Table 8.6, three of these units have no announced plans to convert to gas by 2028 or 2030 and will be subject to the proposed rule.

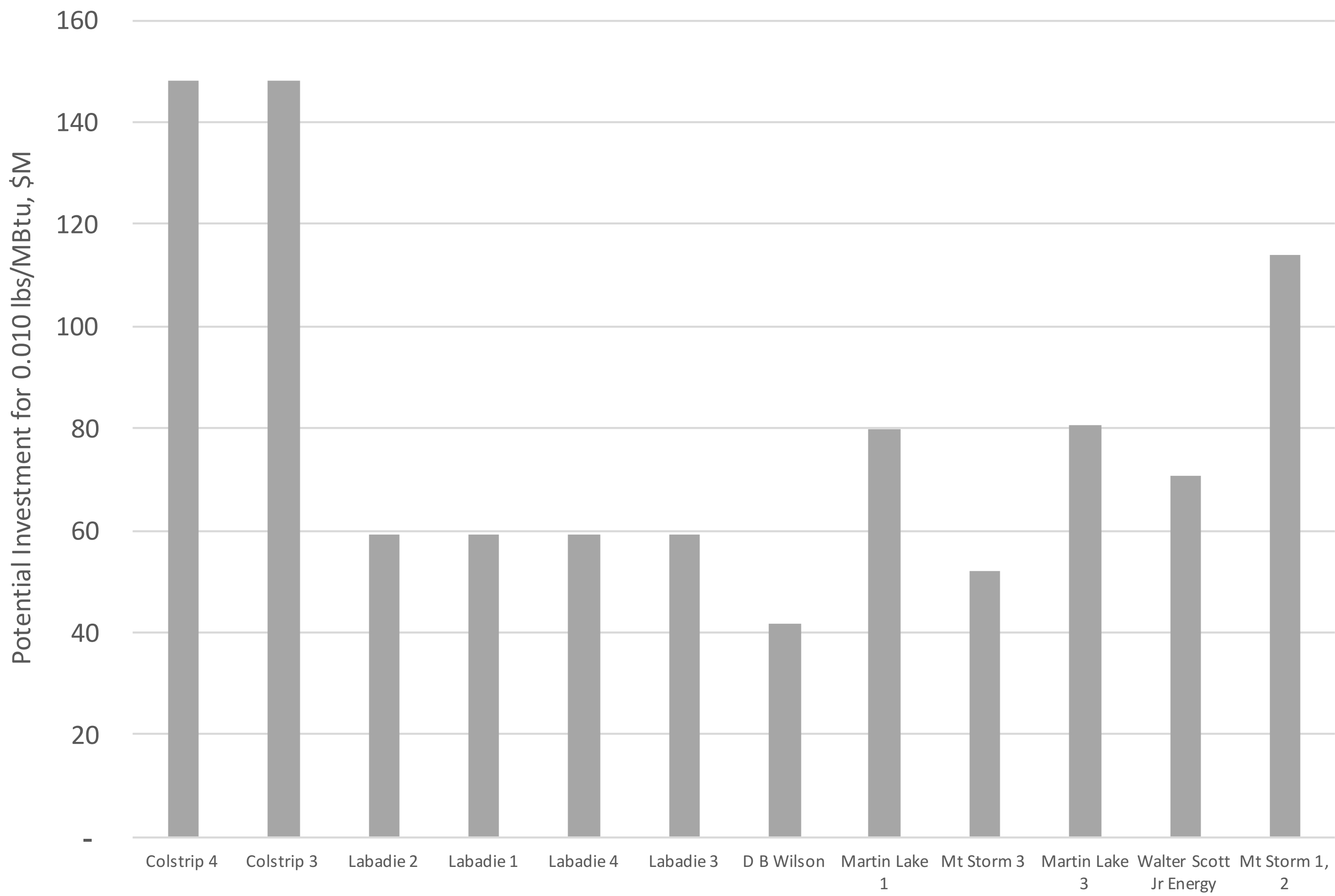
8.2 Summary

The major issues associated with EPA's IPM modeling of the 2028 and 2030 Post-IRA 2022 Reference Case are summarized as follows:

- The 2028 and 2030 Baseline (Post-IRA 2022 Reference Case) used to measure the compliance impacts of proposed rule is flawed and needs to be revised
- Most notably, IPM erred in retiring 55 coal units that will be subject to the proposed rule beginning in 2028.
- IPM retrofitted 27 units with CCS in 2030, 19 of which will be subject to the proposed rule. It is next to impossible for these units to retrofit CCS by 2030.
- The IPM modeled compliance impacts for the proposed rule in 2028 and 2030 is very likely understated.

Appendix A: Additional Cost Study Data

Figure A-1. Unit ESP Investment (per EPA's Cost Assumptions): PM of 0.010 lbs/MBtu



Note: Colstrip costs reflect EPA's approch of retrofitting a fabric filter, as an ESP is not installed at that site.

Table A-1. Technology Assignment for 0.010 lbs/MBtu PM Rate: Industry Study

ESP Minor	ESP Typical	ESP Major Upgrade	FF Cleaning	FF Retrofit
Alcoa/Warrick	East Bend	D B Wilson	Boswell Energy Center	Colstrip 3, 4
Big Bend	General James M Gavin	Labadie	Clover Power Project	
Coronado	Gibson	Labadie	Ghent	
Coronado	Martin Lake 2	Labadie	Gilberton Power/John B Rich	
Crystal River	Milton R Young	Labadie	H L Spurlock	
Crystal River	Mt Storm	Martin Lake 1	Iatan	
Jeffrey Energy Center	Mt Storm		Marion	
Laramie River Station			Mt Carmel Cogen	
Martin Lake			St Nicholas Cogen Project	
San Miguel			Walter Scott Jr Energy Center	
Seminole			WPS Westwood Generation LLC	

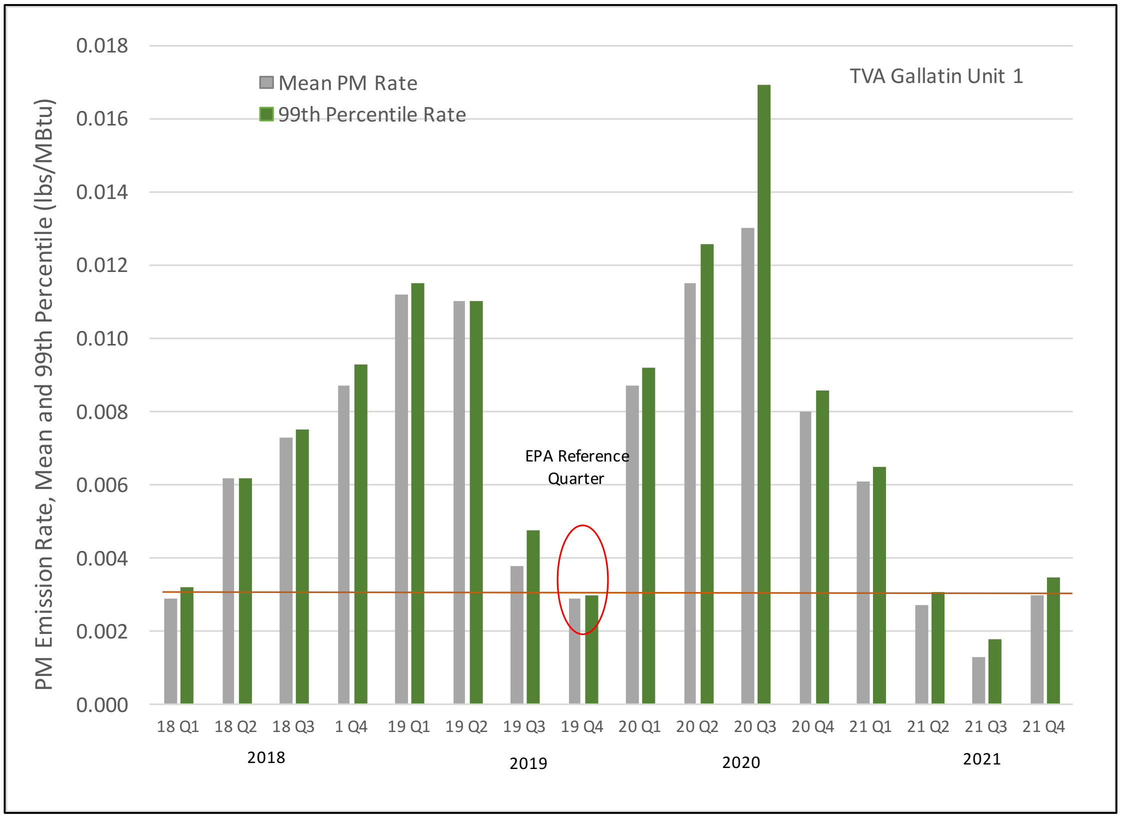
Table A-2 Technology Assignment for 0.006 lbs/MBtu PM Rate: Industry Study

FF O&M Enhancement	**FF Retrofit**	**FF Retrofit**
Antelope Valley	Alcoa/Warrick	Laramie River Station
Bonanza	Belews Creek	Leland Olds 1, 2
Boswell Energy Center Clay Boswell	Big Bend	Martin Lake 1-3
Clover Power Project	Cardinal	Merrimack
Comanche	Colstrip 3, 4	Milton R Young
Ghent	Coronado 1, 2	Monroe 1, 2
Gilberton Power/John B Rich	Crystal River 4, 5	Mt Storm 1, 2
H L Spurlock	D B Wilson	Naughton
Huntington	East Bend	Nebraska City
Iatan	General James M Gavin	R D Green
Louisa	Gibson 1, 3	R S Nelson
Marion	Gibson	Sam Seymour Fayette 1, 2
Mt Carmel Cogen	Independence	San Miguel
Oak Grove 1	IPL - AES Petersburg	Schiller
Sandy Creek Energy Station	James H Miller Jr	Seminole
Scrubgrass Generating 1, 2	Jeffrey Energy Center 1, 2, 3	Trimble County
St Nicholas Cogen Project	Jim Bridger 3, 4	Whelan Energy Center
Twin Oaks Power 1, 2	Labadie 1 -4	White Bluff 1, 2
Walter Scott Jr Energy Center		
Weston		
WPS Westwood Generation LLC		

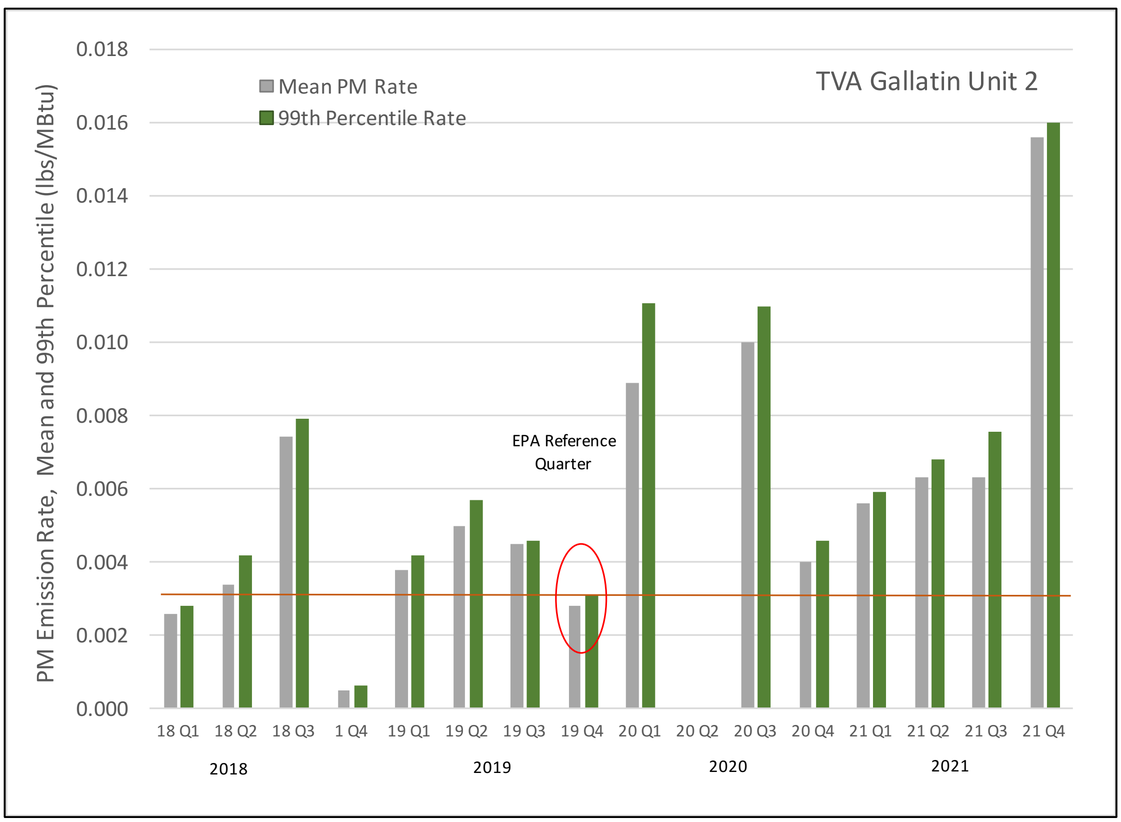
Appendix B: Example Data Chart

Appendix A presents additional examples of units for which EPA's PM sampling and evaluation approach distorted results. These charts contain both mean and 99th percentile data. Data is presented for the following units, for which observations are offered as follows:

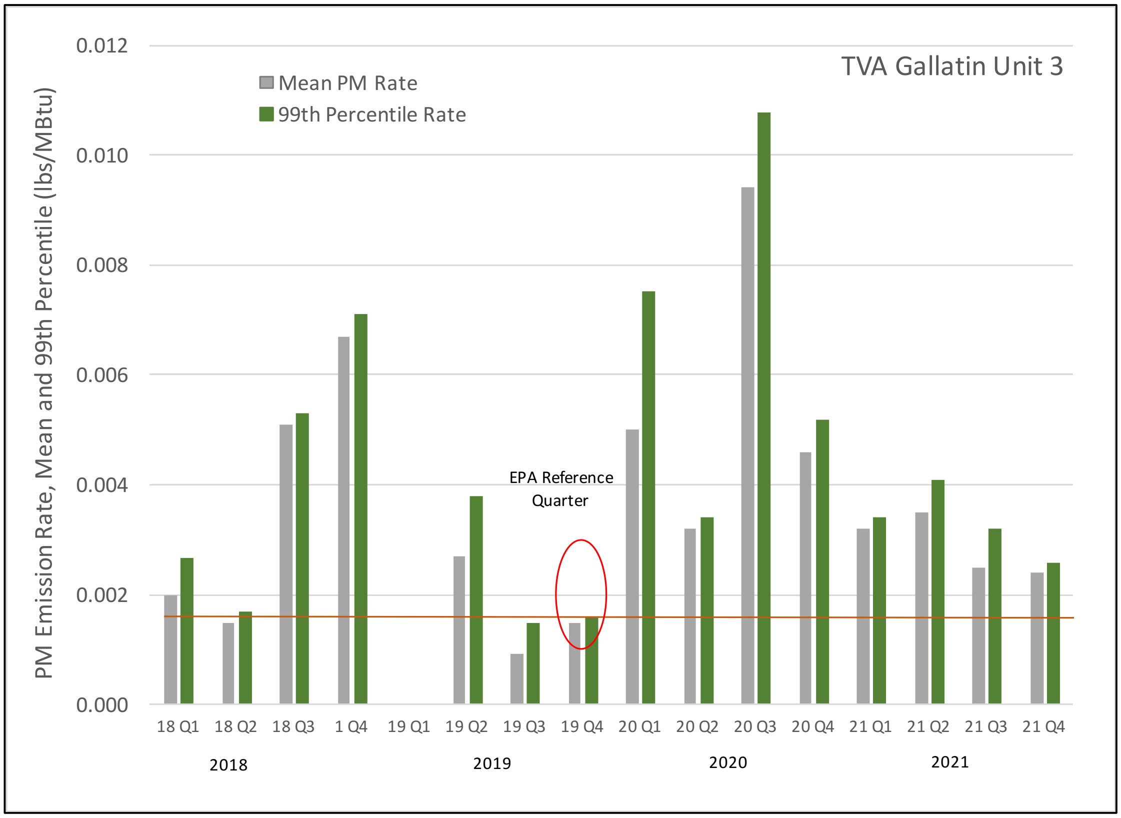
- TVA Gallatin Unit 1. EPA selected 0.0030 lbs/MBtu as the reference PM rate, using Q4 of 2019. Few of the 16 quarters that report lower PM emissions.
- TVA Gallatin Unit 2. EPA selected 0.0031 lbs/MBtu as the reference PM rate, also using Q4 of 2019. Few of the 16 quarters that report lower PM, similar to Unit 1.
- TVA Gallatin Unit 3. EPA selected 0.0016 lbs/MBtu as the reference PM rate, again using Q4 of 2019. Only one quarter (Q3 of 2019) reports lower PM rate.
- TVA Gallatin Unit 4. EPA selected 0.0022 lbs/MBtu as the reference PM rate, using Q1 of 2021. Of the 14 quarters reporting data, two quarters report PM rates equal to this rate, while two are below this rate.
- LG&E/KU Ghent 1. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q2 of 2019. This PM rate represents that reported in previous quarters, but with one exception all subsequent quarters through 2021 report higher PM.
- LG&E/KU Mill Creek Unit 4. EPA selected 0.0035 lbs/MBtu as the reference PM rate, using Q4 of 2021. With the exception of the previous quarter, this value is the lowest of any reported since 2017 by a significant margin.
- Alabama Power Gaston Unit 5. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q1 of 2021. Data for this unit is displayed from Q1 2017 through Q4 2022. Of the 24 reporting quarters (1Q 2017 through 4QW 2022) only 6 quarters have lower PM rates.
- Alabama Power Miller Unit 1. EPA selected 0.004 lbs/MBtu as the reference PM rate, using Q3 of 2017. Data for this unit is displayed from Q1 2017 through Q4 2022. The designated rate represents a significant reduction from approximately half of the reporting quarters since Q1 2020.

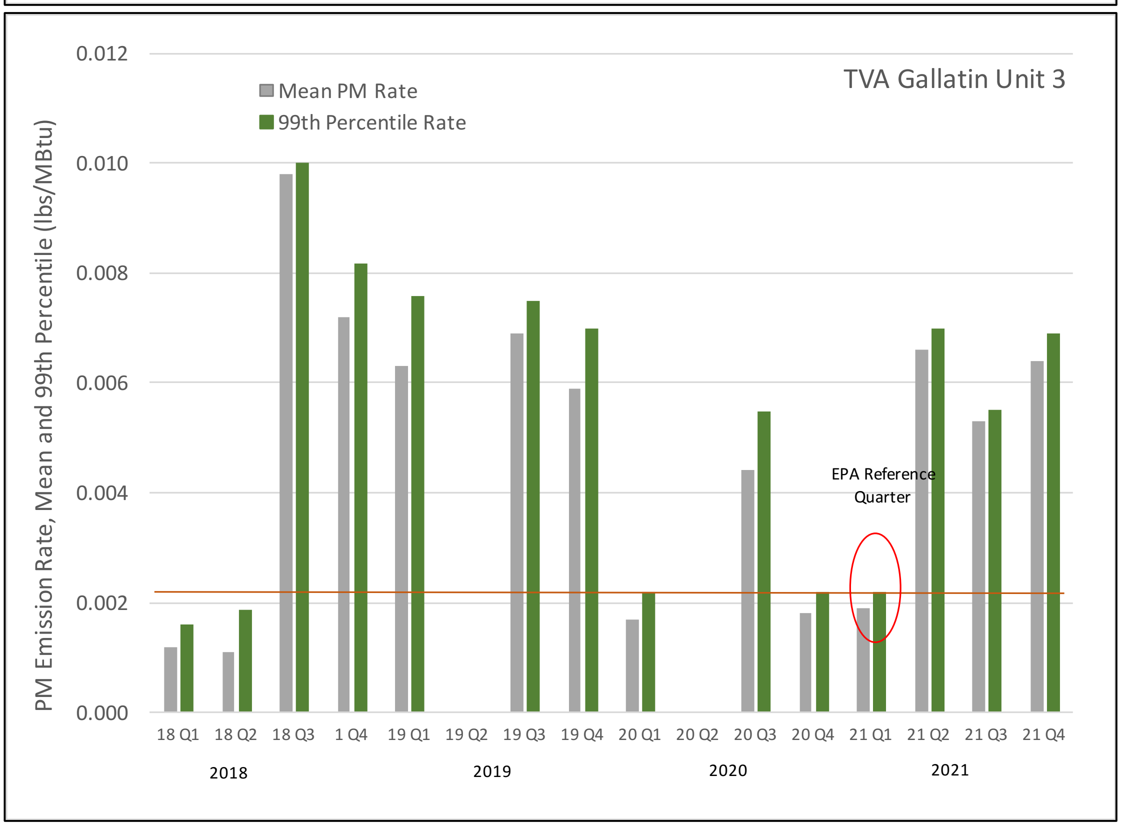


TVA Gallatin Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021

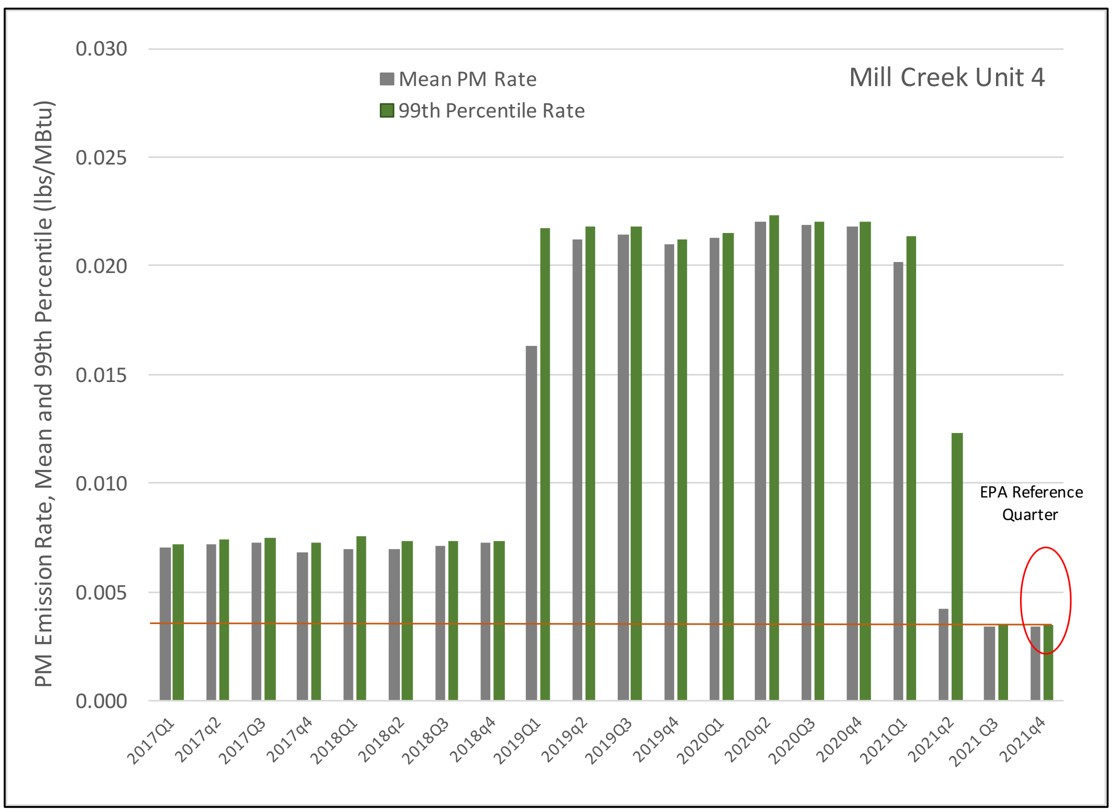


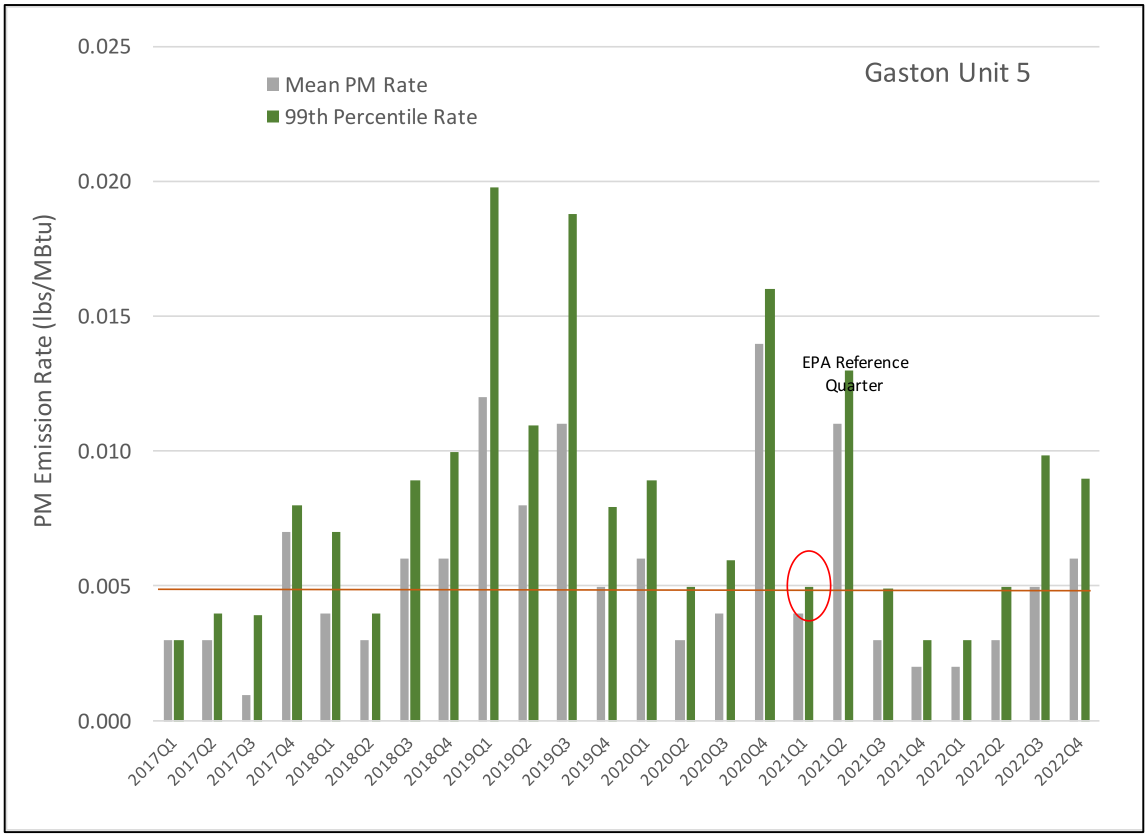
TVA Gallatin Unit 2
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
EPA Reference Quarter
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
EPA Reference Quarter
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


Ghent Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4


Mill Creek Unit 4
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.030
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4



Gaston Unit 5
Mean PM Rate
99th Percentile Rate
EPA Reference Quarter
PM Emission Rate (lbs/MBtu)
0.025
0.020
0.015
0.010
0.005
0.000
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
2020Q2
2020Q3
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2021Q1
2021Q2
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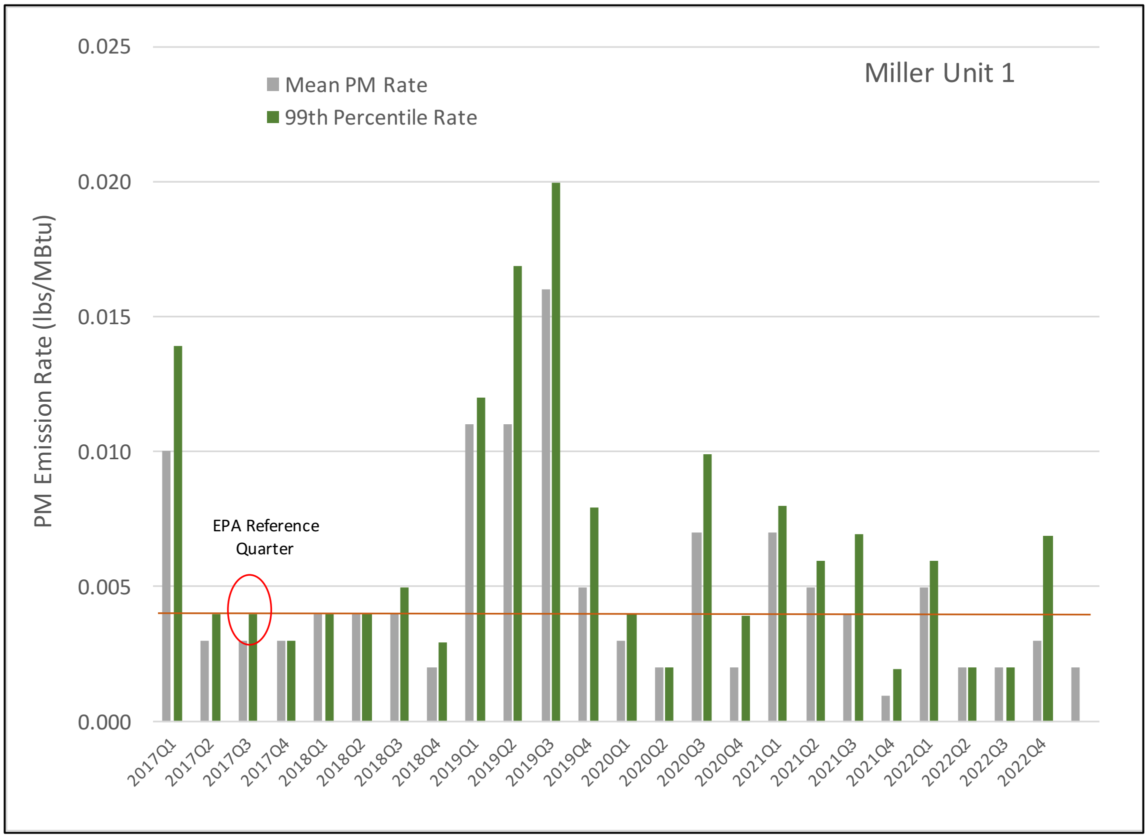
2021Q4
2022Q1
2022Q2
2022Q3
2022Q4



Miller Unit 1
Mean PM Rate
99th Percentile Rate
EPA Reference Quarter
PM Emission Rate (lbs/MBtu)
0.025
0.020
0.015
0.010
0.005
0.000
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
2020Q2
2020Q3
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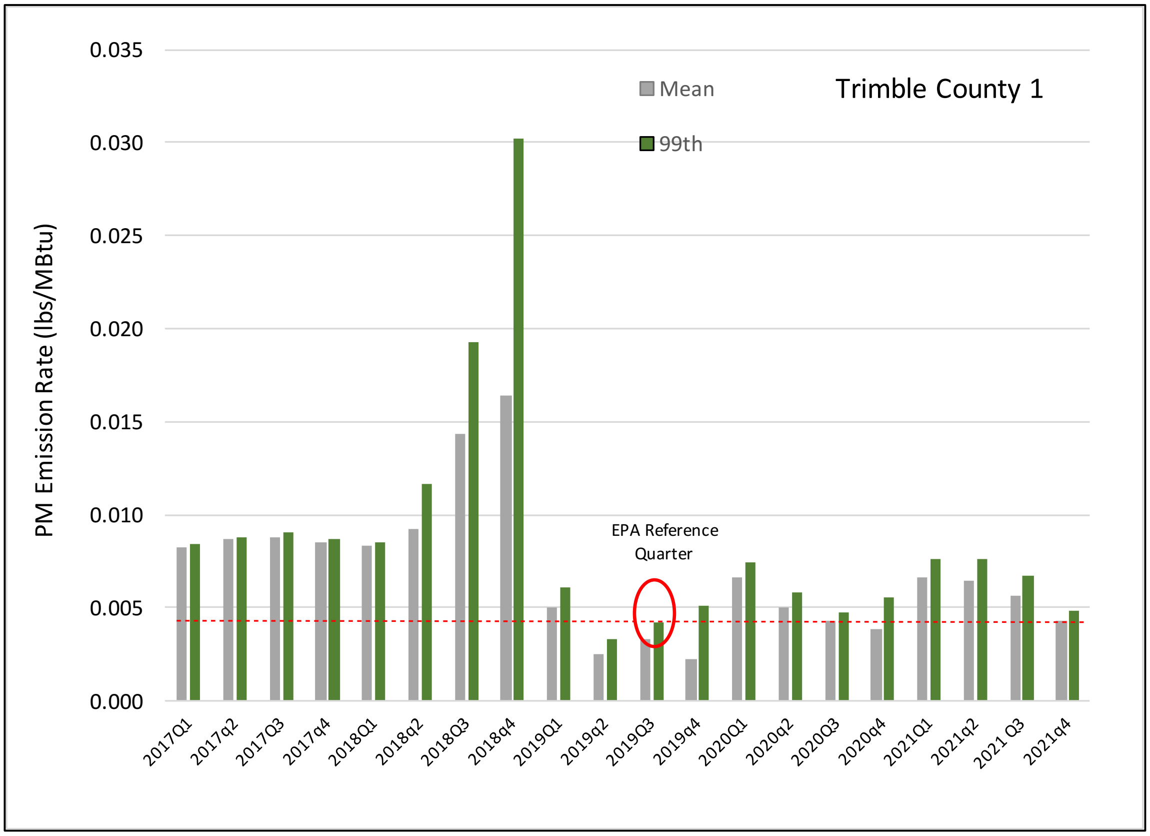
2021Q1
2021Q2
2021Q3
2021Q4
2022Q1
2022Q2
2022Q3
2022Q4



0.035
0.030
0.025
0.020
0.015
0.010
0.005
0.000
PM Emission Rate (lbs/MBtu)
Mean
99th
Trimble County 1
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4

ATTACHMENT C

MEMORANDUM

Date: December 16, 2011

Subject: Emission Reduction Costs for Beyond-the-floor Mercury Rate for Existing Units Designed to Burn Low Rank Virgin Coal

From: Kevin Culligan, SPPD/OAQPS

To: EPA-HQ-OAR-2009-0234

For the final rule, EPA has recalculated the beyond the floor control costs for existing units designed to burn low rank virgin coal using a methodology similar to that used in the IPM analysis done for the MATS proposal. In the final rule, we have not recalculated control costs based on the other methodology used in the proposal which used ACI capital and operating costs provided in the ICR. We have not used that approach because it was based upon an assumption that all units would need to have a baghouse (also known as a fabric filter – FF – either existing or newly installed) in order to meet the MACT PM standard and that the ACI would be used with the baghouse. EPA has considered and used additional information demonstrating that high levels of mercury removal can be achieved with injection of brominated activated carbon and the addition of a FF is not necessary. Furthermore, based on additional analysis related to the PM standard, EPA believes that most lignite units will not need to install new FF, therefore, EPA believes a costing methodology based on this assumption would be inappropriate.

For this analysis, EPA calculated beyond-the-floor costs for mercury controls by assuming injection of brominated activated carbon at a rate of 3.0 lb/MACF for units with ESPs and injection rates of 2.0 lb/MACF for units with baghouses (also known as fabric filters). The rate of 2.0 lb/MACF for fabric filters is consistent with the rate assumed in all other IPM analyses for this rule. The rate of 3.0 lb/MACF for units with ESPs is lower than the rate of 5.0 lb/MACF assumed in the IPM analysis. EPA believes that this rate is appropriate, because a higher rate would likely result in reductions beyond those needed to meet the BTF standard of 4.0 lb/TBtu. Figure 1 in "Activated Carbon Injection for Mercury: Overview"[1] suggests that > 90% control can be achieved at lignite-fired units at a < 2.0 lb/MACF injection rate for units with installed FF and using treated (i.e., brominated) AC. The figure also suggests that > 90% Hg control can be achieved at lignite-fired units at < 3.0 lb/MACF injection rate for units with installed ESPs and using treated AC. As Table 1 below shows, based on the IPM analysis, all units would need to achieve reductions of less than 90%, therefore lower assumed injection rates are appropriate.

[1] *Fuel Processing Technology* 89 (2010) 1310

Table 1 – Emission Reduction Rates Required to Meet Standard of 4 lb/TBtu.

Plant Name	Unit ID	Hg Controls	Existing Controls	Base Hg lbs/Tbtu	Reduction Required, %	Policy Hg lbs/Tbtu
Big Brown	1	ACI	Cold-side ESP + Fabric Filter + SNCR	9.09	55.98	1.01
Big Brown	2	ACI	Cold-side ESP + Fabric Filter + SNCR	9.09	55.98	1.01
Lewis & Clark	B1	ACI	Wet Scrubber	7.68	47.92	0.75
Martin Lake	1	ACI	Cold-side ESP + Wet Scrubber	5.41	26.09	0.56
Martin Lake	2	ACI	Cold-side ESP + Wet Scrubber	5.41	26.09	0.56
Martin Lake	3	ACI	Cold-side ESP + Wet Scrubber	5.41	26.09	0.56
Monticello	3	ACI	Cold-side ESP + SNCR + Wet Scrubber	6.30	36.53	0.96
R M Heskett	B1		Cold-side ESP	7.81	48.77	0.45
R M Heskett	B2		Cold-side ESP + Cyclone	4.76	16.00	0.75
Leland Olds	1		Cold-side ESP	7.68	47.93	0.77
Leland Olds	2		Cold-side ESP	7.81	48.77	0.78
Milton R Young	B1		Cold-side ESP + SCR + Wet Scrubber	4.21	4.93	0.75
Milton R Young	B2		Cold-side ESP + SCR + Wet Scrubber	4.21	4.93	0.75
Stanton	1		Cold-side ESP	7.81	48.77	0.78
Stanton	10		Fabric Filter + Dry Scrubber	7.51	46.76	0.75
Limestone	LIM1		Cold-side ESP + Wet Scrubber	6.75	40.76	1.13
Limestone	LIM2		Cold-side ESP + Wet Scrubber	6.75	40.76	1.13
Dolet Hills	1		Cold-side ESP + Wet Scrubber	8.33	51.98	1.35
Coal Creek	1		Cold-side ESP + Wet Scrubber	4.21	5.07	0.76
Coal Creek	2		Cold-side ESP + Wet Scrubber	4.21	5.07	0.76
Laramie River Station	1		Cold-side ESP + Wet Scrubber	5.31	24.71	0.56
Laramie River Station	2		Cold-side ESP + Wet Scrubber	5.31	24.71	0.56
Antelope Valley	B1		Fabric Filter + Dry Scrubber	7.51	46.76	0.75
Antelope Valley	B2		Fabric Filter + Dry Scrubber	7.51	46.76	0.75
Twin Oaks Power One	U1		Fabric Filter	5.82	31.33	1.35
Twin Oaks Power One	U2		Fabric Filter	5.82	31.33	1.35
Pirkey	1		Cold-side ESP + Wet Scrubber	7.59	47.27	1.35
Coyote	B1		Fabric Filter + Dry Scrubber	7.64	47.66	0.75
Great River Energy Spiritwood Station	1		Cold-side ESP + Fabric Filter + SNCR + Dry Scrubber	7.68	47.92	0.75

EPA also assumed a disposal cost of $25/ton for ash comingled with activated carbon. This cost is consistent with a range of studies. DOE/NETL, in a recent study examining the costs of ACI, assumed total disposal costs of $17/ton for non-hazardous fly ash. They assumed $35/ton for fly ash that would have otherwise been sold for beneficial reuse (lost revenue of $18/ton plus disposal costs of $17/ton for non-hazardous fly ash). [2] In an EPA study, $25 - $30 per ton were assumed as total disposal costs.[3]

EPA recently modeled site-specific disposal costs for the RIA[4] for the proposed rule regulating coal combustion residuals (CCRs), including fly ash. Those costs were examined for units burning low rank virgin coal. The disposal costs varied by state/region. For Texas the incremental costs attributable to Hg control were $18.13/ton, while for North Dakota and Montana, the incremental costs attributable to Hg control were $32.31/ton.

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[3] *Environmental Sci. Technol.* 2006, 1385

[4] Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry. Prepared by US Environmental Protection Agency Office of Resource Conservation & Recovery (ORCR) (formerly Office of Solid Waste) 1200 Pennsylvania Avenue NW (Mailstop 5305P) Washington DC, 20460 USA. Available at http://www.regulations.gov/ docket number EPA-HQ-RCRA-2009-0640-0003, Appendix H.

Based on these key assumptions, EPA projects an average reduction cost of $27,017 per pound of Hg removed. Unit by unit costs are provided in Table 2.

Table 2 – Unit by unit cost estimates for achieving an emission rate of 4 lb/TBtu Hg

Plant Name	Unit ID	Capacity (MW)	Heat Rate (Btu/kWh)	Existing PM Controls	(Base to Policy) Hg remv'd (lbm)	(2007$) unit S/lbm Hg	Total Cost
Big Brown	1	575	11001	Cold-side ESP + Fabric Filter + SNCR	-396	3954	1565723
Big Brown	2	575	10931	Cold-side ESP + Fabric Filter + SNCR	-393	3980	1565723
Lewis & Clark	B1	52.3	13787	Wet Scrubber	-31	22920	704682
Martin Lake	1	750	11512	Cold-side ESP + Wet Scrubber	-332	32175	10671737
Martin Lake	2	750	11202	Cold-side ESP + Wet Scrubber	-323	32174	10383770
Martin Lake	3	750	10784	Cold-side ESP + Wet Scrubber	-311	32309	10038209
Monticello	3	750	11246	Cold-side ESP + SNCR + Wet Scrubber	-359	29249	10487787
R M Heskett	B1	29.37	11985	Cold-side ESP	-17	38871	652353
R M Heskett	B2	75.5	11386	Cold-side ESP + Cyclone	-22	53992	1206545
Leland Olds	1	221	11404	Cold-side ESP	-109	25792	2812406
Leland Olds	2	448	11021	Cold-side ESP	-217	23822	5176973
Milton R Young	B1	250	10661	Cold-side ESP + SCR + Wet Scrubber	-64	51542	3272935
Milton R Young	B2	455	10661	Cold-side ESP + SCR + Wet Scrubber	-116	49018	5665257
Stanton	1	130.3472	10990	Cold-side ESP	-77	26601	2050240
Stanton	10	57.35278	10320	Fabric Filter + Dry Scrubber	-31	30538	935770.1
Limestone	LIM1	831	10102	Cold-side ESP + Wet Scrubber	-372	29034	10797351
Limestone	LIM2	858	10108	Cold-side ESP +	-384	28982	11134608

				Wet Scrubber			
Coal Creek	1	554	11219	Cold-side ESP + Wet Scrubber	-162	48056	7781365
Coal Creek	2	560.3	10818	Cold-side ESP + Wet Scrubber	-158	47982	7576786
Laramie River Station	1	565	11312	Cold-side ESP + Wet Scrubber	-235	34742	8170580
Laramie River Station	2	570	10953	Cold-side ESP + Wet Scrubber	-230	34737	7980115
Antelope Valley	B1	450	10988	Fabric Filter + Dry Scrubber	-264	22315	5888636
Antelope Valley	B2	450	11206	Fabric Filter + Dry Scrubber	-269	22269	5993120
Twin Oaks Power One	U1	152	9497	Fabric Filter	-50	38215	1900963
Twin Oaks Power One	U2	153	10364	Fabric Filter	-55	37778	2064287
Coyote	B1	427	11639	Fabric Filter + Dry Scrubber	-228	22122	5043515
Pirkey	1	675	10693	Cold-side ESP + Wet Scrubber	-349	26185	9140141
Great River Energy Spiritwood Station	1	99	8937	Cold-side ESP + Fabric Filter + SNCR + Dry Scrubber	-46	11694	535381.6
Dolet Hills	1	650	10674	Cold-side ESP + Wet Scrubber	-351	27064	9500464
				Total	-5948		1.61E+08
				Average		27016	

ATTACHMENT D

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Activated carbon injection for mercury control: Overview

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ABSTRACT

Full-scale evaluations of the commercial feasibility of activated carbon injection (ACI) for mercury control in coal-fired power plants have been underway in North America since 2001 through DOE, EPRI and industry-funded projects. Commercial injection systems began to be sold to the power generation industry in 2005 and ACI is now considered the most robust technology for mercury control at many coal-fired units. Successful widespread implementation of this technology throughout this industry will require continued development efforts including: (1) understanding the impacts of technologies to control other pollutants, such as SO_3, for the enhancement of particulate control or selective catalytic reduction (SCR) for NO_x control, (2) options to continue using ash containing activated carbon in concrete, (3) techniques to assure the quality of delivered carbon, (4) techniques to improve the effectiveness of activated carbon, and (5) facilities to produce additional carbon supply. An overview of activated carbon injection for mercury control will be presented including the range of expected control levels, costs, balance-of-plant issues, recent developments to reduce overall control costs for many common air pollution control configurations, and developments to overcome complications caused by some new control configurations. An update on carbon supply and progress on ADA's activated carbon manufacturing facility will also be provided.

1. Introduction

The power industry in the US is faced with meeting state imposed regulations, as well as expected federal legislation, to reduce the emissions of mercury compounds from coal-fired plants. In 2005 the Federal Clean Air Mercury Rule (CAMR) was signed into law and included mercury control requirements for new sources and a phased in implementation schedule for existing sources. Although the CAMR was vacated by the US District court in 2008, new plants permitted between 2005 and 2008 include mercury control equipment. In addition, over 100 existing plants have installed or are planning to install mercury control equipment in response to state regulations or consent decrees negotiated between a state and a power producer.

Several options have been considered to control mercury from coal-fired power plants. At some plants, effective mercury control is achieved as a result of synergistic effects with pollution control equipment designed primarily to remove other pollutants. For example, a plant firing bituminous coal with a selective catalytic reduction (SCR), which has been installed to reduce nitrogen oxides (NO_x) into N_2 and H_2O, can be effective at converting elemental mercury into oxidized mercury, which is water soluble. If the plant also uses a flue gas desulfurization (FGD) system where the flue gas contacts a wet alkaline slurry to remove sulfur dioxide (SO_2), a large fraction of the water-soluble mercury is also removed. However, plants firing western fuels that have SCRs and FGD systems do not achieve high mercury removal levels. Therefore, many plants, especially those firing western fuels, will need separate mercury removal systems to achieve the necessary emissions levels. For such plants, activated carbon injection (ACI) has been shown to be a cost-effective, reliable option.

In March 2009, the Institute of Clean Air Companies (ICAC) reported that mercury control systems had been ordered for 135 plants in the US and Canada, representing more than 55 GW of generation. Of these, 54 GW, or more than 98%, are ACI systems. The majority of the ACI systems ordered, 41 GW, were planned for units firing western coals (lignite or subbituminous) where ACI is most effective. It is expected that new federal regulations will be implemented in the future that will require mercury control systems on additional units.

2. Background: activated carbon injection for mercury control

Activated carbon is an effective sorbent for mercury capture from flue gas. Many years of research, development and over 50 full-scale demonstrations have shown that ACI can greatly reduce mercury emissions from most configurations, even where native mercury removal is low. ACI is the commercial mercury-specific air pollution control option of choice, but success at specific sites

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requires an understanding of factors that can impact effectiveness. Some of these can be addressed through careful system design, such as ensuring even distribution of the sorbent in the flues gas, providing sufficient time for the sorbent to contact and adsorb the mercury, and optimizing plant operation to maintain operating temperatures within an favorable range. Some challenges will require continued development efforts, such as improved sorbents, unless a change in fuel or the existing particulate control equipment can be implemented.

Activated carbon distribution is determined by the injection grid design, which requires access to ports in select locations, and is affected by mixing in the duct at the injection location, the particle size of the sorbent injected, and the amount of conveying air used to enhance distribution. Residence time varies with the configuration of the plant and distance to the particulate collection device as well as the type of particulate collection device (electrostatic precipitator (ESP) vs. fabric filter (FF)).

The effectiveness of activated carbon for mercury control is temperature dependent. Specifically, the mercury capacity of a particular sorbent typically increases as the flue gas temperature decreases. The flue gas temperature is primarily determined by plant design and operating factors. Depending on plant specifics such as flue gas constituents and operation of the particulate control device, mercury removal is relatively effective at temperatures below 350 °F. For most plants, typical air preheater outlet temperatures are between 250 and 400 °F and temperature can become a factor to consider when projecting mercury removal effectiveness.

Some flue gas constituents can aid mercury removal (i.e. halogens), while others can hinder it (i.e. SO_3 or NO_2). Halogens and hydrogen halides (primarily chlorine and bromine) are present in the flue gas from the coal or can be introduced through coal or flue gas additives. In low-halogen flue gas, halogen-treated activated carbon can be very effective at capturing mercury.

Examples of the impact of sulfur, specifically SO_3, on mercury control are presented in Fig. 1. This graph is a compilation of results from several activated carbon injection demonstration programs sponsored by the US DOE and industry. Several trends can be observed from the data in Fig. 1, including:

1. Fabric filters, including TOXECON™ units, which include fabric filters installed downstream of ESPs, are more effective when used in conjunction with activated carbon injection than ESPs alone.
2. Sites with low-halogen flue gas, including subbituminous coals from the Powder River Basin (PRB) and those with spray dryer absorbers (SDA) can achieve high levels of mercury removal using halogen-treated activated carbon.

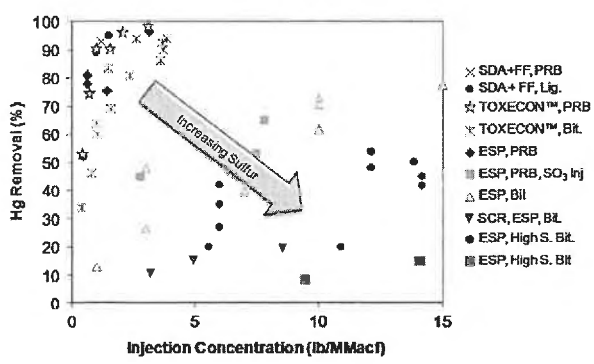

Fig. 1. Compilation of results from DOE mercury control programs.

3. ACI at sites firing western fuels, such as PRB coals or lignite (Lig.) coals, results in higher mercury removal than sites firing bituminous (Bit.) coals.
4. As the sulfur level of the coal increases, or when the SO_3 concentration is increased as a result of other pollution control devices, as will be discussed in the next section, the effectiveness of the activated carbon for mercury control decreases.

3. Industry-wide feasibility of activated carbon injection for mercury control

Although activated carbon injection is already a commercial mercury control option for many sites firing western fuels, continued development efforts have the potential to further expand implementation at sites where ACI is already an appropriate option and to increase applicability for other sites. Continued improvements in the technologies will involve: (1) reducing impacts created by other air pollution control equipment and operations, (2) continued improvements by activated manufacturers and equipment designers, (3) additional solutions to eliminate the impact of activated carbon on fly ash sales for use in concrete production, (4) procedures to ensure the quality of delivered carbon, and (5) increasing the production to sufficient quantities of activated carbon to meet industry-wide demand.

Interferences in the performance of ACI are often associated with increased levels of SO_3 and NO_2 created by equipment designed to reduce the emissions of other flue gas constituents. For example, some older-generation catalysts in SCR systems convert SO_2 to SO_3, sufficient amounts of which have been observed to impact the effectiveness of ACI for mercury control. These systems are being phased out and will not pose a problem for most sites. However, across the US, approximately 25 GW of power are produced from units firing PRB and low-sulfur bituminous coal that inject nominally 5–15 ppm SO_3 to improve ESP performance. SO_3 is used to "condition" the flue gas to improve particulate capture in ESPs on units firing low-sulfur coal. Chemicals to replace SO_3 for flue gas conditioning that do not detrimentally impact activated carbon performance are under evaluation. If such replacements are successfully utilized, it will increase the number of plants where ACI can be implemented.

The primary cost of mercury control with ACI is the sorbent. Additional reductions in costs can be achieved through proper system design, plant operation to maintain acceptable temperatures, and limiting SO_3 and NO_2 in the flue gas. Sorbent usage can be further decreased by lowering the mass mean diameter, and thus increasing the bulk surface area, of the activated carbon. During recent tests on units firing western subbituminous coal from the Powder River Basin (PRB), milling activated carbon resulted in a reduction of over 50% in activated carbon requirements [1,2]. Further tests are necessary to determine if the activated carbon usage can be further reduced, and the resulting effect on mercury removal.

Many units firing western fuels sell their fly ash as a replacement for Portland cement in the manufacture of concrete. In 2006, over 72 million tons of fly ash were produced in the US, 46% of which were used in concrete, concrete products, and grout [3]. Minute air bubbles entrained in the concrete matrix improve the durability of the concrete over freeze/thaw cycles. Carbon in fly ash is typically not desirable because it adsorbs chemicals designed to maintain air content in the concrete as it sets. Plants that sell their ash and choose to utilize ACI risk losing ash sales and potentially face landfilling the ash. Fly ash land filling costs are significant and can become one of the largest operating costs for plants after labor and fuel [4]. Options to preserve ash sales, while using ACI for mercury control, include separating the activated carbon-laden ash from the bulk of the fly ash by using

EPRI-patented techniques such as TOXECON™ [5] or TOXECON II™ [6], reducing the amount of powdered activated carbon required through techniques such as on-site milling, or use of a specialized ash compatible activated carbon. These specialized activated carbon sorbents are fairly new to the market and are being evaluated for their mercury control effectiveness and their impact on concrete properties. Another option being evaluated is the use air entraining agents that are not impacted by activated carbon. In addition, there are groups evaluating the effectiveness of separating the carbon and the ash through novel means such as triboelectrostatic separation.

Widespread use of ACI in the power industry will require that sufficient quantities are available and the quality and consistency of delivered activated carbon is maintained. During demonstration programs from 2001 through 2009, activated carbon deliveries of consistent quality were typically experienced. In a few cases, as vendors responded to the increased demand, key characteristics of the activated carbon varied, such as the density of the bulk material, bromine level, particle size, or the abrasive qualities of the sorbent [7]. These changes often led on significant impacts to the mercury removal, quantity of sorbent required, calibration of the feed equipment, and/or conveying system operation.

ADA Environmental Solutions (ADA), a leading developer of activated carbon injection technology and commercial activated carbon equipment supplier, estimates that upcoming federal and state regulations will result in tripling of the annual US demand for activated carbon to nearly 1.5 billion pounds from approximately 450 million pounds, requiring rapid expansion of production capacity. This will exceed the existing supply because the US activated carbon production plants that are already operating at near-capacity. ADA is currently constructing the largest activated carbon production plant ever built using state-of-the art components. Other manufacturers are also discussing expansion of their existing production capability. As production expands, it will be critical to work with reputable vendors and to develop internal processes to assure the quality of the as-delivered product.

4. Summary

The development and commercialization of ACI is a clear example of the dedication of emissions control technology developers, the power generation industry, and the DOE working together to meet the challenge of reducing mercury emissions from coal-fired power plants. ACI offers promise as a primary mercury control technology option for many configurations and an important trim technology for others that are not able to achieve 90% mercury capture by other means. As state regulations are implemented and the potential for a federal rule becomes more imminent, technologies are being developed to further reduce costs and limit the balance-of-plant impacts associated with ACI. In conjunction with the technology development, additional activated production facilities and quality assurance procedures are being developed to assure that industries needs are met.

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ATTACHMENT E

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 2

Particulate & Mercury Control Technology Evaluation & Risk Assessment for Proposed MATS Rule

Final

June 23, 2023

Project No.: A14559.010

S&L Nuclear QA Program Applicable:

☐ Yes

☒ No

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Chicago, IL 60603-5780 USA
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1. INTRODUCTION

1.1. PURPOSE

Sargent & Lundy (S&L) was retained by Minnkota Power Cooperative, Inc. (Minnkota) to evaluate potential filterable particulate matter (PM) and mercury (Hg) emissions reductions in response to the proposed rule to amend the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal-and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as Mercury and Air Toxics Standards (MATS) published on April 24, 2023 that would require additional filterable PM and Hg emissions reductions on the Milton R. Young (MRY) Station Unit 2. These proposed revisions are the result of EPA's review of the residual risk and technology review (RTR) from May 22, 2020. Based on the proposed rule, EPA is planning to revise the filterable PM standards from 0.030 lb/MMBtu to 0.010 lb/MMBtu and is soliciting comments to consider even more stringent standard of 0.006 lb/MMBtu or lower. For lignite-fired units, EPA is also proposing to revise and tighten mercury emission standard from 4.0 lb/TBtu to 1.2 lb/TBtu to make it same as other units firing bituminous and subbituminous coal.

S&L reviewed the existing MRY Unit 2 PM and Hg control technologies to determine potential optimizations that could achieve incremental emission reductions as well as consider new PM and Hg control technologies. S&L prepared an evaluation of available control technologies including technical feasibility and effectiveness, and costs based on the current emissions from the unit. S&L's evaluation was completed based on past experience on similar projects, as well as input from established original equipment manufacturers (OEMs) regarding predicted performance for the lignite application at MRY Unit 2.

1.2. FACILITY BACKGROUND

The MRY station is located approximately seven (7) miles southeast of Center, North Dakota or forty (40) miles northwest of Bismarck, North Dakota on ND Highway 25 at 3401 24th Street SW, Center, North Dakota 58530. MRY station provides energy to the Midcontinent Independent System Operator (MISO) system. MRY station consists of two (2) units. Both MRY units are lignite-fired Babcock and Wilcox (B&W) cyclone boilers. The Unit 1 single wall cyclone boiler was placed into service in 1970 and has a typical output capacity rating of 257 MWg (gross). The Unit 2 opposed wall cyclone boiler (Carolina type, radiant pump assisted natural circulation) was placed into service in 1977 and has a typical output capacity rating of 470 MWg (gross). Both boilers fire North Dakota lignite coal supplied from BNI Coal, Ltd.'s Center Mine located in close proximity to the plant. Both units utilize selective non-catalytic reduction (SNCR) and separated overfire air (SOFA) systems for NOx control, fuel additive (halide injection) system and non-halogenated powdered activated carbon (PAC) for Hg control, dry electrostatic precipitators (ESP) for PM emissions control, and wet flue gas desulfurization (WFGD) systems for sulfur dioxide (SO_2) control.

1.3. DIFFERENCES IN MRY UNIT 1 AND 2 DESIGN & OPERATION

MRY Unit 1 and 2 have the same air pollution control equipment in series; however, the design of the equipment differ in ways other than unit MWg size. Of particular note, the Unit 2 ESP design attributes are superior to Unit 1, with use of a wider plate spacing (12 vs. 9 inches), and a higher specific collection area (375 ft^2/1000 actual cubic feet per minute (acfm) vs. 288 ft^2/1000 acfm). However, the Unit 2 ESP design consists of the first 2 fields' specific corona power = 160 W/1000 acfm and the last 2 fields = 240 W/1000 acfm, which is consistent with historic ESP designs where transformer-rectifier (T/R) sets were typically selected to provide lower current density at the inlet sections, where the dust concentration will tend to suppress the corona current, and to provide higher current density at the outlet sections, where there is a greater percentage of fine particles. In comparison, the Unit 1 ESP design does not follow this approach, with all fields' specific corona power = 493 W/1000 acfm and is currently achieving significantly lower PM emissions than Unit 2. The single Unit 1 WFGD vessel has four (4) slurry recycle pumps (SRPs). Each of the two (2) WFGD vessels on Unit 2 have five (5) SRPs.

Furthermore, manual cleaning of the boiler on Unit 1 is also able to include air preheater (APH) cleaning, whereas the large hoppers below the Unit 2 APH prevent APH washes from being completed during short-term boiler cleaning outages. The Unit 1 offline cleaning occurs on average every 110-115 days and requires the unit to be offline typically for three (3) days. The Unit 2 offline cleaning (only including APH tube rodding) occurs on average every 85-90 days and requires the unit to be offline typically for four (4) days.

1.4. CURRENT BASELINE EMISSIONS

Minnkota provided the past five (5) years of emissions to establish baseline emissions used for this evaluation. The baseline emissions were developed using data submitted by Minnkota to the EPA between January 01, 2018 through December 31, 2022 as part of emissions reporting requirements. For PM emissions, a 30-boiler operating day rolling average was selected as the baseline PM emission calculation methodology to be in-line with the permit reporting requirements. For Hg emissions, the maximum 30-boiler operating day experienced during the evaluation period was selected as the baseline Hg emission.

Table 1-1 — Baseline Unit 2 PM & Hg Emissions

Parameter	Units	Unit 2
PM Emissions	lb/MMBtu	0.015
Hg Emissions	lb/TBtu	3.90

2. PARTICULATE TECHNOLOGY EVALUATION

As part of this evaluation, PM control technologies were evaluated based on achieving post-upgrade emissions limits in accordance with the proposed emissions included in the April 24, 2023, MATS proposed rule, 0.010 lb/MMBtu and potentially 0.006 lb/MMBtu. The description and assessment of each control option are discussed in the sections below.

2.1. OPTIONS TO REACH 0.010 LB/MMBTU

2.1.1. Increased Boiler Cleaning Outages

When manual cleaning of the boiler occurs, the following unit operation indicates reduced economizer outlet temperatures and subsequently APH outlet temperatures. The fly ash resistivity is reduced at lower temperatures making it easier to capture in the ESP. The decrease in temperature would also slightly reduce the volumetric flow through the ESP, which may also allow for improved flow and velocity through the ESP, subsequently improving the ESP overall performance. Although scheduling short term outages to complete cleaning of the boiler on a regular basis (regardless of near-term long-term outages) has shown the ability to maintain emissions below the baseline emissions, a PM emission of 0.010 lb/MMBtu likely cannot be achieved and therefore this option was not considered further.

2.1.2. Flow & Distribution Devices

Uniform gas and dust distribution to each ESP casing will allow for uniform treatment/conditions of each casing to facilitate optimal performance of each. Concentrated flow and/or dust to a casing will require that casing to work harder than the others, ultimately contributing to and/or causing other operating inefficiencies within the ESP to reduce its PM removal capabilities. Replacement of existing inlet and outlet flow & dust distribution devices to achieve the latest standards of the Institute of Clean Air Companies (ICAC) Publication No. EP-7 will improve the ESP overall performance. Implementation of other flow correction devices to minimize sneakage between cells and/or around collecting fields as well as to minimize particle re-entrainment from hoppers and collecting surfaces when rapped can also be implemented, as required, to meet best industry practices, if not already implemented as part of ESP designs.

A detailed assessment including computational flow dynamic (CFD) analysis and physical flow model studies would be performed to determine the design and placement of all flow and dust distribution devices. New designs of perforated plates (with rappers) would be implemented to allow for the easy removal of fly ash into the first field hopper to minimize the potential fly ash accumulation in the inlet plenum. Although PM emissions reductions are expected to be achieved with this option, a PM emission of 0.010 lb/MMBtu likely cannot be achieved and therefore this option was not considered further.

2.1.3. Increased Power Supply

In an ESP, the collection efficiency is proportional to the amount of corona power supplied to the unit, assuming the corona power is applied effectively (maintains a good sparking rate). The resulting corona current charges the PM in the flue gas which are then attracted to the grounded, oppositely charged collecting plates. For a given flow rate, the collection efficiency will increase as the corona power is increased. To achieve a high collection efficiency, corona power is usually between 100 and 500 W/1000 acfm, but newer ESP installations have been designed for as much as 800-900 W/1000 acfm.

Increasing the power delivered into the ESP casing for this option would be done by replacing the T/R sets with higher rated power supplies, e.g. switch mode power supplies (SMPS), also referred as high frequency T/R sets, or 3-phase power supplies. Replacement of the T/R sets will require new cables, as the existing cables for 2-phase will need to be upgraded to accommodate 3-phase; cables are assumed to be able to be pulled while the unit continues to operate. Further assessment would be required to determine all electrical infrastructure modifications required, including the ability to reuse the existing MCC and T/R set controls. Although PM emissions reductions are expected to be achieved with this option, a PM emission limit of 0.010 lb/MMBtu with adequate operating margin likely cannot be achieved and therefore this option was not considered further.

2.1.4.Additional ESP Field

As ESP performance does depend on the number of fields in the direction of flue gas flow, the addition of another field will increase the amount of power that can be supplied to the ESP and provide incremental removal of the filterable PM. As approximately 80% of the ash is expected to be collected in the first field, with decreasing degrees of particulate removal in the following fields, the last field in the ESP casing is expected to have the least amount of fly ash removed. This option can be implemented by either increasing the sectionalization of the last field (adding a T/R set) or potentially by utilizing the ESP outlet nozzle to retrofit another independently operated ESP field.

Sectionalization in the direction of gas flow is not feasible without a rebuild of the fields to be sectionalized as the current high voltage frames span the entire length of the field. Therefore, this option is only feasible if a new field is added at either the inlet or outlet of the existing ESP casing (assuming space available). However, the retrofit implications of this option would be considered to be a large capital retrofit project in lieu of an equipment optimization. This option is not anticipated to provide significant enough cost savings compared to the other large capital retrofit options that will be evaluated later in this evaluation. Therefore, this option is not considered further.

2.1.5.Additional ESP Casing

Installation of additional ESP casings in parallel to the existing Unit 2 ESP casings would increase the specific collecting area (SCA) and improve the velocity and treatment time of the existing ESP casings. The smaller wing ESP casings would be installed adjacent to the existing ESP casings, one added to north of Casing A and one added to the south of Casing B. The new wing casings will utilize a separate support structure and new power supplies to be independent, stand-alone structures. It is anticipated that modifications to the inlet and outlet ductwork would be required to evenly balance the flow to the new casings. The hoppers of the new ESP casings would be tied into the existing fly ash handling system. Although PM emissions reductions are expected to be achieved with this option, a PM emission limit of 0.010 lb/MMBtu with adequate operating margin likely cannot be achieved and therefore this option was not considered further.

2.1.6.ESP Rebuild

Rebuilding the existing Unit 2 ESP would involve replacement of all internals, while only reusing the outer shell/walls, hoppers, support structures, and ash conveying system. To accomplish the rebuild of the ESP casings, the roof, T/R sets, high voltage bus ducts, top end frames, intermediate roof beams, the top section of the inlet and outlet nozzles and all internal components of the existing ESPs will be removed, and replaced with new equipment. The flow distribution and correction devices in the inlet and outlet plenums would be replaced to optimize the flue gas and fly ash distribution to the casings. The hot and cold roofs would also be replaced as well to accommodate construction activities.

Before moving forward with rebuild, a structural integrity and thickness study should be completed on the entire structure to ensure that the steel has not thinned as a result of normal long-term option. The design of the support structure (casing, structural members, and determination of ESP loads to steel), support steel and foundation will need to be reviewed to verify if acceptable for reuse or if modifications are required for the weight change in the ESP casings as a result of the rebuild, which may result in additional reinforcement required. The existing ash handling systems would be reused without requiring any modifications for the incremental increase in the amount of ash collected. It would be assumed that the complete rebuild of the ESP casings and optimization of the flow distribution/collection devices in the inlet and outlet nozzles should be capable of achieving no net increase in the current pressure drop across the ESP and therefore would not require modifications or replacement of the existing ID fans.

The level of rebuild and repair to the existing ESP casings will require a longer construction outage, most likely requiring a twelve (12) week outage, if not longer. Limited access to the Unit 2 casings will also limit the construction sequence, and may cause delays, further extending the outage. Winter weather conditions experienced at the site could also prolong the construction process. Additional construction personnel would likely be required to complete work in multiple areas in an effort to reduce the outage duration.

With this option, the PM emissions are estimated to potentially achieve an emission rate of 0.008 lb/MMBtu. However, vendors would likely have to complete a more detailed qualitative study in order to provide a guarantee and would require baseline testing to qualify ESP inlet and outlet emissions.

2.2. OPTIONS TO REACH 0.006 LB/MMBTU

To achieve PM emissions that would allow for compliance with the more stringent proposed standard, a baghouse would be required. It should be noted that a baghouse will likely not provide sufficient operating margin to achieve the proposed 0.006 lb/MMBtu emission rate. It will likely be challenging to obtain a guarantee below 0.006 lb/MMBtu from baghouse OEMs. However, a baghouse is not considered to be economically feasible[1] and is therefore not evaluated further. The baghouse installation options that could be considered, described below, and the expected timeline for implementation of this control option, described in Table 2-2, are included for reference only.

- Conversion of ESP to Baghouse:
    - The existing ESP casings would be reused and ESP internals and all roof mounted equipment would be removed. A vertical partition wall, running in the direction of gas flow from the hopper bend line to the tube sheet, would be constructed in the center of each ESP casing.
- Polishing Baghouse (Downstream of ESP):
    - The existing ESP would continue to operate. Due to the reduced inlet ash loading, a polishing

[1] A high-level estimation of the cost effectiveness of a baghouse retrofit on MRY Unit 2 is approximately $162k/ton, based on the annualized capital and O&M costs ($/yr) divided by the annual reduction in annual emissions (ton/yr).

baghouse can be designed using a 6.0 air-to-cloth (AC) ratio, which allows for a reduced footprint compared to a 4.0 AC ratio sized to handle the entire unit fly ash loading.
    - There is not adequate space available adjacent to the existing ESP casings for placement of a baghouse. Therefore, long tie-in ductwork will be required to route flue gas to an open area where the baghouse can be constructed. As such, the reduced size of the polishing baghouse is not anticipated to provide significant enough cost savings when compared to a baghouse that utilizes a 4.0 AC ratio.
- Baghouse (Primary PM Collection):
    - The existing ESP would be abandoned in place (could be demolished at a later date). As mentioned previously, long tie-in ductwork will be required to route flue gas to an open area where the baghouse can be constructed while the unit continues to operate in order to minimize the tie-in outage duration.

A baghouse is expected to have a pressure drop of 8 in. w.c., but could be higher depending on the location of the baghouse in relation to the tie-in to the existing flue gas path. The current axial fans are already operated very close to their stall curve, and do not have any pressure drop operating margin. Therefore, either replacement of the existing ID fans or installation of new booster fans would be required to accommodate the additional pressure drop through the baghouse.

2.3. PARTICULATE EMISSIONS SUMMARY

Table 2-1 below provides a summary of the post-upgrade achievable emission rate for the feasible PM control option evaluated to achieve a proposed PM emission limit of 0.010 lb/MMBtu. The estimated emission rates included in the following tables are considered to be representative of an average emission rate that could be achieved under normal operating conditions. The emission rates provided **should not be** construed to represent an enforceable regulatory or proposed permit limit. Corresponding regulatory and/or permit limits must be evaluated on a control system-specific basis taking into consideration normal operating variability (i.e., a minimum additional 20% margin would likely be needed to account for operating margin).

Table 2-1 — Unit 2 PM Emissions Summary

Parameter	Control Efficiency Note 1	Projected Emissions Note 2 (lb/MMBtu)	Expected Emissions (ton/year)
Baseline (Dry ESP)	**--**	**0.015**	**254**
ESP Rebuild	46.7%	0.008	135

Note 1 – Control efficiency is based on incremental improvement achieved with the option in addition to baseline dry ESP operation (e.g. not to be misconstrued as a total percent removal from uncontrolled PM emissions).
Note 2 – No compliance margin is included in these estimates. The emissions rate projections should not be used as an achievable limit for these upgrades.

2.4. TIMELINE FOR INSTALLATION

A high-level implementation schedule that outlines the time needed for the project steps necessary for the implementation of the feasible control options are summarized below. It should be noted that although a baghouse is not considered to be economically feasible, the control option is included in the summary below for reference on the expected timeline required for implementation of this control option. Other project-related activities, such as the time needed to obtain internal project approval, financing or permitting, if required, are not included. It should be noted that these time frames are separate from the regulatory time frames for EPA to take final action on the Proposed MATS RTR.

Lead times of equipment that would be used in these types of retrofits have been observed to be double or triple the lead times typically provided by suppliers before the COVID pandemic, with longer durations observed for electrical and instrumentation and control equipment. With continued supply-chain issues, it is anticipated that longer and longer lead times may be required that are difficult to quantify at this time. Therefore, timelines represented are estimated based on past project durations and not reflective of post-pandemic market delays nor the limited number of experienced OEMs capable of providing the equipment.

Table 2-2 — PM Control Implementation Schedule

PM Control Option	Design/ Specification/ Procurement (months)	Detail Design/ Fabrication (months)	Construction/ Commissioning/ Startup (months)	Minimum Total (months)
ESP Rebuild	8	16	12	36
Baghouse	10	20	18	48

3. MERCURY TECHNOLOGY EVALUATION

3.1. MERCURY EMISSIONS BACKGROUND

3.1.1. Mercury Speciation

Mercury (Hg) is contained in varying concentrations in different coal supplies. During combustion, Hg is released in the form of elemental Hg in the high temperature combustion zone of a boiler. As the combustion gases cool, a portion of the elemental Hg transforms or oxidizes to ionic Hg. However, the amount of elemental Hg that oxidizes is dependent on the cooling rate of the gas and the presence of halogens in the flue gas. Ultimately, there are three possible forms of Hg:

- Elemental (Hg^0):
  - The conversion of elemental Hg to the other forms depends upon several factors including cooling rate of the gas, presence of halogens or sulfur trioxide (SO_3) in the flue gas, amount and composition of fly ash, presence of unburned carbon, and the installed APC equipment.
  - Hg^0 is insoluble in water and therefore removal requires injected sorbents or must be converted to another form to be captured, depending on the installed APC equipment.
- Ionic or Oxidized (Hg^{++} or Hg^{2+}):
  - In contrast to elemental Hg, ionic Hg is highly water soluble, allowing for collection in water streams that may be utilized in certain APC equipment and subsequently leave the process with the solid by-product or as a constituent in the purge water.
- Particulate-bound:
  - Particulate-bound Hg typically is bound to fly ash or unburned carbon. Particulate-bound Hg is efficiently removed from the flue gas by the particulate control device, making it desirable to convert as much Hg as possible to particulate-bound Hg.
  - High SO_3 levels have been shown to inhibit the binding of ionic Hg to fly ash or Hg sorbents. The addition of halogens increase the conversion of elemental and ionic Hg to particulate-bound Hg.

The proportion of the various Hg forms is referred to as Hg speciation. As such, Hg speciation testing has indicated that the distribution of Hg species varies with coal type. The effectiveness of post-combustion Hg control technologies is highly influenced by the Hg speciation in the flue gas, with gaseous oxidized (or ionic) Hg compounds (i.e. $HgCl_2$) being easier to capture by downstream APC equipment.

3.1.2. Lignite Coal Variability

Industry experience has shown that lignite coal deposits vary significantly in quality, including fuel combustion performance, mineral content, and Hg content, resulting in a coal that can change on a day-to-day basis depending on the coal seam being mined at the time. For example, during the 2005 Energy & Environmental Research Center (EERC) sixty (60) day testing on MRY Unit 2,[2] the coal samples analyzed ranged from 6.22

[2] Refer to the EERC "Large-Scale Mercury Control Technology Testing for Lignite-Fired Utilities - Oxidation Systems for Wet FGD" report (Cooperative Agreement No. DE-FC26-03NT41991) dated March 2007 for further details on the testing completed from March 15, 2005 to May 15, 2005 on MRY Unit 2.

lb/TBtu to 10.9 lb/TBtu (Hg content varied from 0.05 to 0.25 ppm, and averaged 0.112 ± 0.014 ppm on a dry coal basis). As such, units firing lignite coal with lower heating values have to accommodate frequently changing coal quality and require a wide range of flexibility to account for instances of firing high Hg seams of coal to consistently achieve adequate operating margin below the required Hg emission limit.[3]

The variability of the projected lignite coal quality received from the Center Mine from 2025 through 2036 is shown in Table 3-1.

Table 3-1 — Center Mine Ultimate Coal Analyses (As-Received)

Fuel Parameter	Units	Average	Minimum	Maximum
Carbon	wt.%	40.53	39.73	41.24
Hydrogen (fuel-based)	wt.%	2.78	2.71	2.82
Nitrogen	wt.%	0.30	0.26	0.34
Sulfur	wt.%	0.86	0.68	1.07
Oxygen (by difference)	wt.%	9.97	9.47	10.83
Moisture	wt.%	38.83	38.53	39.25
Ash	wt.%	6.73	6.00	7.87
Higher Heating Value (HHV)	Btu/lb	6,625	6,489	6,739
Mercury Content	ppm	0.091	0.053	0.184
Estimated Hg Emission	lb/TBtu	8.41	4.79	17.42

3.1.3.Hg Removal with ESPs

For ACI on ESP applications, 80% of Hg capture occurs in the flue gas, and 20% occurs on the dust within the ESP (as the dust on the collecting plates are consistently removed as part of the process). Therefore, for ESP applications, achieving ideal mixing and residence time to allow for elemental Hg to oxidize to ionic Hg and for Hg to be adsorbed on the carbon particles (of the PAC or unburned carbon content in the fly ash) is critical. It should be noted that this ratio is the exact opposite for baghouse applications, i.e. 20% capture in-duct and 80% capture on the dust of the filter cake accumulated in the baghouse. For this reason, fabric filters can result in extremely high Hg capture and can improve the capture with any Hg sorbent.

3.1.4.Existing System Limitations

Documented evidence of a lignite unit achieving 1.2 lb/TBtu or below has not been found/reviewed at the time of this report. Minnkota personnel recently completed short-term parametric testing in May 2023 to determine the Hg emissions that could be achieved by maximizing the existing fuel additive and PAC injection. Even when maximizing the fuel additive rate in addition to maximizing the non-halogenated ACI addition, an emission rate of 1.2 lb/TBtu was not able to be achieved. Due to the variability of the coal, a longer period of testing would be required to gauge the Hg emissions that could be achieved just using the capacity within the existing equipment.

[3] Based on Response of Minnkota Power Cooperative Clean Air Act Section 114 Request, dated July 29, 2022.

3.2. INCREMENTAL HG CONTROL ON A LIGNITE UNIT

As mentioned previously, S&L is not aware of any documented evidence of a lignite unit achieving 1.2 lb/TBtu or below. As such, the following sections describe issues that need to be resolved/tested to establish if it is feasible to achieve a 1.2 lb/TBtu Hg emission rate with sufficient operating margin on a lignite unit and if so, develop an overall Hg compliance approach that likely would consist of a suite of control approaches. It should be noted that any achievable Hg emission should not be construed to represent an enforceable regulatory or proposed permit limit. Corresponding regulatory and/or permit limits must be evaluated on a control system-specific basis taking into consideration normal operating and coal variability (i.e., a minimum additional 20% margin or higher would likely be needed to account for coal fluctuations and operating margin).

3.2.1.Increased Oxidation of Elemental Hg

Recent 2011 Hg speciation data measured at the Unit 2 stack, with no control technologies, indicated the Hg emissions consisted of approximately 98.3% elemental Hg, 0.8% oxidized Hg, and 0.9% particulate Hg. Recent operating data from a retired Hg process monitor indicates that the Unit 2 Hg emissions, with the currently installed Hg control technologies, consisted of approximately 86% elemental Hg, and 14% oxidized Hg. Because the current Hg emissions are made up mostly of elemental Hg, the unit emissions would benefit from an increased amount of halogen in an attempt to oxidize the elemental Hg in the flue gas. The additional halogen (chlorine, iodine, and bromine) can be added to the PAC, to the coal, or both.

The current fuel additive injection could be increased and/or replaced with a different halogen-based additive. In addition, the current non-halogenated PAC would be replaced with a more expensive halogenated PAC. The increased amount of halogen present is expected to increase the amount of elemental Hg that is oxidized to be more easily captured on the surface area of the PAC and in downstream APC.[4]

3.2.2.Increased PAC

It is anticipated that additional halogenated PAC (i.e. more than the current capabilities of the existing equipment) will need to be injected for the increased amount of oxidized Hg to be efficiently captured. However, preliminary feedback received from PAC suppliers have indicated that demonstration testing would be required to determine a PAC dosage rate and the emissions rate that can be achieved when considering the Hg content variability of the lignite. Therefore, additional modifications that may be required cannot be concluded at this time; however, it is likely that the existing lances and transport piping would need to be replaced to accommodate a higher injection rate. As the existing PAC storage silo is shared by Units 1 and 2, it is likely that a separate silo would be required for Unit 2 to ensure adequate supply, turndown flexibility, and reliability is achieved to maintain compliance with a defined Hg emission limit.

The degree of increased PAC injection rates can have an impact on the ESP performance as the increased amount of carbon particles that have low resistivity will decrease the overall resistivity of the fly ash (can cause particles to rapidly lose their charge on arrival at the collecting plate and become re-entrained). If/when

[4] It should be noted that the existing PAC silo is not currently compatible to store halogenated PAC due to the material of construction of the fluidizing air nozzles and may also require an internal coating of the silo to prevent corrosion. Additional assessment will be required to determine modifications required to reuse the existing silo, and may be subject to the brominated PAC utilized.

additional testing is completed to determine the supplier recommended brominated PAC injection rate, PM emissions should also be closely monitored to confirm no longer term impacts are caused by the increased ACI rate. In order to mitigate potential increases or deviations for the current PM emissions, it would be reasonable to anticipate some ESP upgrades (operational changes and/or equipment optimizations) to be required to ensure the ESP maintains its current performance.

3.2.3. Increased Contact

Increasing the degree of flue gas and PAC mixing can optimize the sorbent utilization to ensure adequate mixing of the oxidized Hg and PAC is achieved, which potentially could result in the use of less PAC to achieve the same Hg emission rate. Similarly, additional testing and evaluation would be required to determine the beneficial incremental Hg removal improvement that could be achieved. Additional mixing could be implemented by either adding static mixers into the flue gas path and/or using a more advanced injection lance design to increase sorbent dispersion relative to a straight lance design to optimize sorbent usage.

Increased contact time could also be achieved by relocating the injection lances upstream of the APH.[5] Hg reduction effectiveness with PAC has been shown to be temperature limited, as the absorption capacity of the carbon is reduced at temperatures above approximately 350°F. Although flue gas temperatures downstream of the APH are more ideal for capture, temperatures upstream of the APH are within an ideal zone for mercuric halogens to be formed, taking advantage of the additional halogen introduced with the PAC. Furthermore, for applications with SO_3 concentrations above 5 ppm in the flue gas (as-is on the MRY units), carbon active sites may be preferentially occupied by SO_3. Although adsorption rates slow down above 350°F, injection upstream of the APH is sometimes considered to lower the impact of SO_3 competition. Furthermore, tubular APH designs will not offer as much mixing compared to Ljungstrom type APHs; therefore, relocating the injection lances upstream of the APH will likely only achieve added residence time for adsorption to occur in lieu of additional mixing. Therefore, the high temperature environment and resulting residence time for injection at the APH inlet would need to be evaluated further.

3.2.4. WFGD Re-Emission Control

Oxidized Hg is highly water soluble and exists in vapor phase at back-end equipment flue gas temperatures. WFGDs readily capture approximately 90% of oxidized Hg because it is highly soluble, but will not remove elemental Hg. However, re-emission of Hg is possible in some circumstances when Hg precipitates out in scrubber solids (mercuric sulfide or equivalent) and the scrubber slurry converts some of the oxidized Hg back into elemental form. Re-emission of elemental Hg can be mitigated through the use of a sulfide-donating liquid reagent additive that enhances the Hg capture within the WFGD by decreasing soluble Hg in the WFGD slurry. Testing would be required to determine the amount of re-emission currently occurring based on recent operating conditions.

3.3. MERCURY EMISSIONS SUMMARY

Presently, there is not any publicly available information to determine if improvements to any of the above categories (individually or in combination) can achieve a Hg emission of 1.2 lb/TBtu or below on a lignite unit.

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[5] It should be noted that this approach is patented by Alstom, and use of this approach would need to consider intellectual property implications.

Therefore, additional testing would be required to establish if it is feasible to achieve a 1.2 lb/TBtu Hg emission rate with sufficient operating margin on a lignite unit and if so, develop an overall Hg compliance approach that likely would consist of a suite of control approaches to achieve this rate on MRY Unit 2.

In summary, additional testing would include, but not be limited to, the following:

- Hg speciation data upstream of the ESP, upstream of the WFGD and at the stack (with no controls, current operation and maximum capacity of existing Hg control equipment, and test conditions for other listed items)
- Performance with increased concentrations of current fuel additive system, including additional injection locations, as well as potentially testing other halogen-based fuel additives than what is currently used.
- Performance with halogenated PAC, considering capabilities of existing Hg control equipment and increased injection rates (while also considering other test conditions for other listed items). Note that due to the limitations of the existing equipment, a separate test skid will be required to facilitate this testing campaign.
- If WFGD re-emission is determined to be occurring based on Hg speciation upstream and downstream of the WFGD, the performance of a re-emission additive can also be tested.

As mentioned previously, PAC suppliers have indicated that testing would be required in order to obtain any guaranteed performance. Therefore, recommended consumption and/or injection rates to determine the modifications and/or new systems required are not available at this time to develop the subsequent cost of the suite of Hg controls needed to achieve adequate operating margin below a 1.2 lb/TBtu Hg emission limit on MRY Unit 2.

4. SUMMARY

The existing MRY Unit 2 PM and Hg control technologies were found to not be capable of achieving the proposed emissions included in the April 24, 2023, MATS rule: filterable PM emissions limit of 0.010 lb/MMBtu and potentially 0.006 lb/MMBtu and Hg emissions limit of 1.2 lb/TBtu.

The evaluation of available PM control technologies found that an ESP rebuild would be required to achieve the proposed PM emission limit of 0.010 lb/MMBtu considering the need for adequate operating margin. However, testing to determine the baseline ESP inlet flow profile, ESP inlet and outlet emissions, and amount of PM removal occurring across the WFGD will likely be required in order for a vendor to complete a detailed qualitative study required to provide a PM emission guarantee. A baghouse will likely not provide sufficient operating margin for compliance with the more stringent 0.006 lb/MMBtu proposed emission limit; furthermore, this alternative was not considered to be economically feasible, and OEMs may not offer a PM emission guarantee with sufficient operating margin. A significant outage will be required to complete an ESP rebuild on MRY Unit 2, likely requiring the unit to be offline 12 weeks or longer as part the retrofit. Due to current post-pandemic market delays and the limited number of experienced OEMs capable of completing an ESP rebuild, it is highly likely that the implementation of this large-scale capital project will take longer than the estimated 36-month implementation schedule.

At the time of this evaluation, no evidence or examples demonstrating that an operating lignite unit could achieve the proposed Hg emission limit of 1.2 lb/TBtu were found. As the Hg content of the lignite coal fired at MRY Unit 2 can range from as low as 4.8 lb/TBtu to as high as 17.4 lb/TBtu, a wide range of flexibility in Hg control to account for instances of firing high Hg seams of coal to consistently achieve adequate operating margin below the proposed Hg emission limit will be required. Additional testing will also be required to navigate the challenges of Hg speciation, flue gas temperature, flow profile/mixing, residence time, and coal variability for application on a lignite fired unit to establish if it is feasible to achieve a 1.2 lb/TBtu Hg emission rate with sufficient operating margin. Furthermore, PAC suppliers have indicated that testing would be required in order to obtain any guaranteed performance. Once testing is completed, recommended consumption/injection rates, required flexibility of the suite of Hg control approaches and the subsequent costs of the modifications and/or new systems required to achieve adequate operating margin below a 1.2 lb/TBtu Hg emission limit on MRY Unit 2 can be developed.

ATTACHMENT F

[redacted]

Analysis of

Proposed EPA MATS Residual Risk and Technology Review and

Potential Effects on Grid Reliability in North Dakota

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North Dakota Transmission Authority

April 3, 2024

Assisted by:

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Center of the American Experiment

Contents

Executive Summary

On behalf of the North Dakota Transmission Authority (NDTA), the Center of the American Experiment prepared this study to analyze the potential impacts of EPA's proposed revisions to the Mercury and Air Toxics Standards (MATS) Rule on North Dakota's power generation and power grid reliability.

Our primary finding, which is drawn substantially from the Rule's administrative record, is that the proposed changes are likely not technologically feasible for lignite-based power generation facilities, will foreseeably result in the retirement of lignite power generation units, and will negatively impact consumers of electricity in the Midcontinent Independent Systems Operator (MISO) system by reducing the reliability of the electric grid and increasing costs for ratepayers.

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

Moreover, building such replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Replacing these lignite facilities with new wind, solar, natural gas, and battery storage facilities would cost an additional $1.9 billion to $3.8 billion through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts. Accounting for projected increases in demand for electricity, we assess that if the MATS Rule goes into effect in the near future, by 2035, the MISO grid will experience up to an additional 73,699 megawatt hours (MWh) of unserved load, with an economic cost of up to $1.05 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Section A: North Dakota's Power Environment

North Dakota Transmission Authority (NDTA)

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

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

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

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

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

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

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

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

FERC-Recognized Regional Transmission Organizations and Independent System Operators

(www.ferc.gov)

Generation Adequacy, Transmission Capacity & Load Forecast Studies

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

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

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

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

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

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

Current North Dakota Generation Resources

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

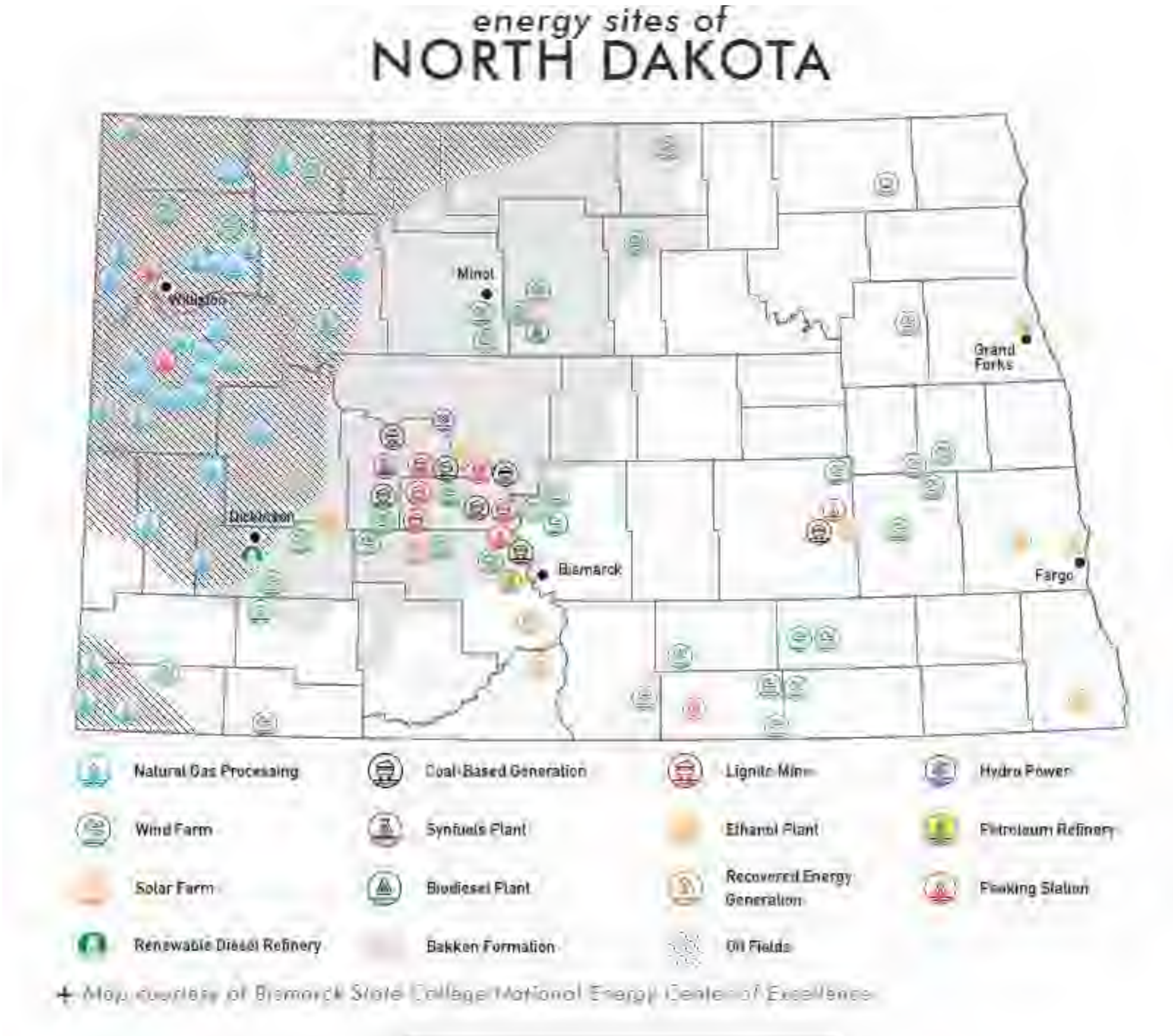
1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW since it is intermittent. This is representative of the

amount that is estimated to be available for the peak demand in the summer.

- Solar Generation: Although North Dakota currently lacks utility-scale solar generation facilities in operation, some projects are in the queues of regional transmission organizations like MISO and SPP, indicating potential future development in this area.

2. Thermal Coal Generation:
   - North Dakota currently operates thermal coal generation at six locations, comprising a total of 10 generating units with a combined capacity of approximately 4,048 MW.
   - The average capacity factor for these generating plants ranged from 65% to 91% in 2021, excluding the retired Heskett Station.
   - Rainbow Energy operates the Coal Creek Station and the DC transmission line that transports ND produced energy to the Minneapolis region. Rainbow Energy is assessing a CO_2 capture project for the facility. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity on the DC line.
3. Hydro Generation:
   - North Dakota has one hydro generation site equipped with 5 units, boasting a total capacity of 614 MW.
   - However, the average capacity factor declined to approximately 43% in 2021 due to limitations imposed by water flow in the river, particularly during drought years.
4. Natural Gas Generation:
   - North Dakota operates three sites for electric generation utilizing natural gas, comprising 21 generating units with a total capacity of 596.3 MW.
   - These units include reciprocating engines and gas turbines, with variation in summer capacity influenced by the performance of gas generators in hot weather.
   - Total natural gas generation in North Dakota remained steady from 2019 through 2021, amounting to 1.445 GWhr in 2021.
5. Total Generation:
   - The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW.
   - Wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW due to its intermittent nature, down from 4,250MW of installed capacity, representing the estimated amount available during peak summer demand. However, newer installations have demonstrated slightly higher capacity for accreditation.

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

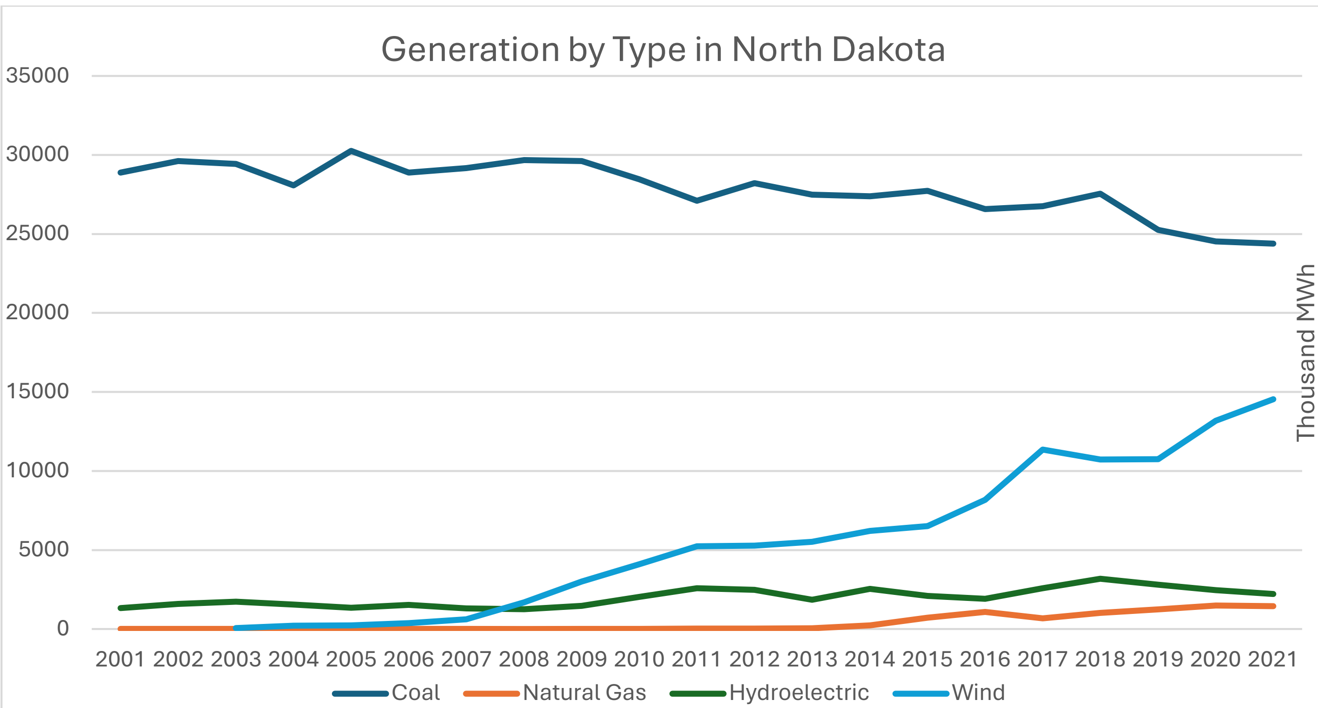


Electric Generation Market & Utilization

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

According to data from the Energy Information Administration, in 2020, North Dakota generated a total of 42,705 MWh of electricity from all sources, with 46% of this total being exported beyond the state's borders over two large high voltage direct current lines (HVDC), which serve load in the neighboring state of Minnesota and multiple 345kv and 230kv alternating current (AC) transmission lines serving surrounding states. Wind generation accounted for 31% of North Dakota's total electricity generation in 2020, highlighting the growing significance of renewable energy in the state's energy portfolio. Notably, industrial demand in North Dakota experienced substantial growth, expanding by nearly 11% in 2020.

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



Grid Resource Adequacy and Threats to Growth Opportunities

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

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

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

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

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

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

Grid Reliability Is Already Vulnerable

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

NERC's 2023 Reliability Risk Assessment

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

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

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

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

[1] NERC. "North American Reliability Assessment." North American Electric Reliability Corporation, May 2023, https://www.nerc.com/news/Headlines%20DL/Summer%20Reliability%20Assessment%20Announcement%20May%202023.pdf.
[2] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

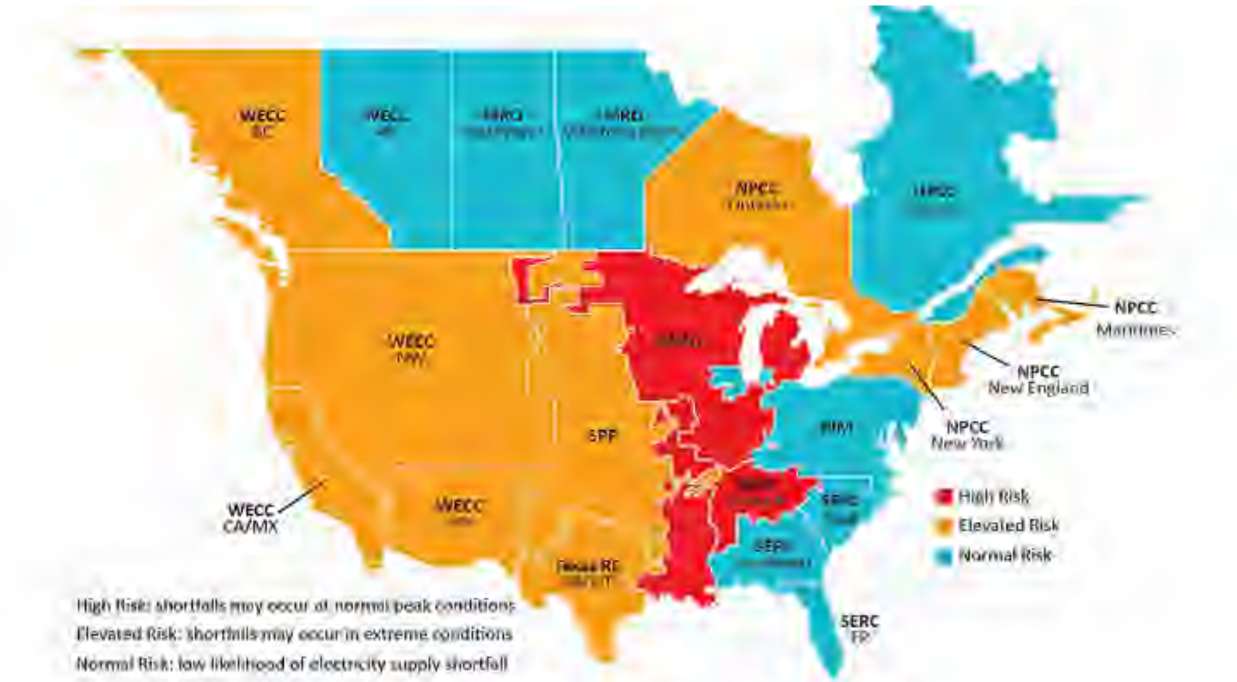


Figure 1: Risk Area Summary 2024–2028[6]

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

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

MISO's Response to the Reliability Imperative (2024)

On February 26, 2024, the Midcontinent Independent System Operator (MISO) released "MISO's Response to the Reliability Imperative[4]," a report which is updated periodically to reflect changing conditions in the 15-state MISO region that extends through the middle of the U.S. and into Canada. MISO's new report explains the disturbing outlook for electric reliability in its footprint unless urgent action is taken. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliability attributes.

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

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

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

margin requirements.[5]

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

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

> *"While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability.* ***In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.***
>
> *In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.*
>
> *MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline.* ***If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*** *The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources*."

Despite these reliability warnings issued by MISO, EPA did not consider the reliability impacts of the proposed MATS rules required emission control upgrades and additions to units. It is likely that many units that would have to incur millions of dollars to retrofit emissions controls to comply with this proposal would not do so.[6]

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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

[6] Rae E. Cronmiller, "Comments on Proposed National Emission Standards for Hazardous Air Pollution: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," The National Rural Electric Cooperative Association, June 23, 2023, Attention Docket ID NO. EPA-HQ-OAR-2018-0794.

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

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

The escalating frequency of grid events requiring emergency procedures, such as the 48 Maximum Generation events in MISO since 2016 and the increasing number of alerts issued by SPP, over 194 alerts issued in 2022, underscores the urgency of addressing transmission congestion and bolstering reliable generation capacity. The economic growth and security of North Dakota are directly tied to the timely development of new transmission facilities in tandem with dependable dispatchable electric generation.

The impacts of grid strain extend beyond the energy sector, affecting multiple industries, ratepayers, and overall economic stability. Volatile wholesale prices and transmission congestion undermine business operations and investment confidence, hindering economic growth and prosperity. Moreover, reliable electricity supply is critical for essential services, including Department of Defense facilities, underscoring the broader implications of grid reliability issues. Achieving a balanced generation portfolio requires careful consideration of reliability and resilience under all weather conditions, especially amidst the electrification of America and the imperative to safeguard public welfare and security.

Additionally, over 50% of the electricity generated in North Dakota is exported to neighboring states, magnifying the ripple effects of any regulations impacting dispatchable electricity generation resources. By responsibly managing the generation portfolio and prioritizing generation adequacy, North Dakota and the nation can seize significant opportunities for economic growth, innovation, and sustainable development.

Section B: The Proposed MATS Rule Will Dramatically Affect North Dakota Lignite Electric Generating Units

The revised MATS Rule includes a proposal to eliminate the "low rank coal" subcategory established for lignite-powered facilities by requiring these facilities to comply with the same mercury emission limitation that currently applies to Electric Generating Units (EGUs) combusting bituminous and subbituminous coals, which is 1.2 pounds per trillion British thermal units of heat input (lb/TBtu). EPA's proposal is a substantial lowering of the current mercury limitation for lignite fired EGUs, which is 4.0 lb/TBtu.[7,8] The proposal also includes a significant reduction in the particulate matter standard applicable to all existing units from 0.03 lb/mmBtu to 0.01 lb/mmBtu. Because North Dakota is somewhat unique to the degree in which its power generation relies upon lignite coal, the compliance costs for this Rule, while likely to substantial for coal plants all around the country, will be most acutely inflicted upon North Dakota's lignite-based power generation facilities.

Numerous comments in the administrative record, including from the regulated facilities in North Dakota and the North Dakota Department of Environmental Quality, provided EPA with notice that the new emission standards are not technologically feasible, will impose crippling compliance costs that may require facility retirement, and will result in a significant portion of the dispatchable power provided by coal-generation facilities being taken off the grid. This report will summarize some of those concerns in the section that follows, however, a full study of the technological feasibility of complying with the new emissions standards is beyond the scope of this report. For purposes of this report, we assume the regulated facilities and state regulator were forthright in their concerns about the feasibility of lignite-based facilities meeting the new standards.

The Proposed MATS Rule Eliminates the Lignite Subcategory for Mercury Emissions

Although the Proposed Rule affects all coal electrical generating utilities (EGUs), reducing the lignite emissions standards to levels of other coal ranks effectively eliminates the lignite sub-category and would have drastic consequences for North Dakota's lignite EGU industry.[9] EPA original decision to regulate separately a subcategory of lignite units was well-supported with documented information and a thorough analysis. In its comments filed in this Docket, on June 22, 2023, the North Dakota Department of Environmental Quality (hereafter DEQ) encouraged EPA to review that prior determination and reaffirm the need for a lignite subcategory and the associated emissions standards.[10]

Specifically, DEQ summarized the original MATS proposal in 2011 and final MATS rule in 2012, in which EPA presented a body of evidence in support of the lignite category. For example, the EPA wrote:

> "For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter free

[7] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[8] [8] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, (June 2, 2023) ("Cichanowicz Report").

[9] EPA characterizes lignite as "low rank virgin coal". 88 Fed. Reg. 24,854, 24,875. For this comment letter, lignite will be used in place of low rank virgin coal.

[10] David Glatt, P.E., "Comments on the Proposed Rulemaking Titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Docket ID No. EPA-HQOAR-2018-0794)," On Behalf of the North Dakota Department of Environmental Quality, June 22, 2023.

basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units.

The boiler of a coal-fired EGU designed to burn coal with that heat value is larger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories."

As explained by DEQ, EPA has not provided any scientific justification to support abandoning the lignite subcategory and requiring those facilities to comply with the emission standards applicable to other coal types. The most EPA identified in support of its proposal was a reference to information nearly 30 years old, which predated EPA's original determination.

The Proposed MATS Rule Will Not Provide Meaningful Human Health or Environmental Benefits

Section 112(f)(2) of the CAA directs EPA to assess the remaining residual public health and environmental risks posed by hazardous air pollutants (HAPs) emitted from the EGU source category.[11] Further regulation under MATS is required only if that residual risk assessment demonstrates that a tightening of the current HAP emission limitations is necessary to protect public health with an ample margin of safety or protect against adverse environmental effects.

When reviewing whether to revise the MATS Rule, EPA determined that further regulation of mercury and other HAPs would be unnecessary to address any remaining residual risk from any affected EGU within the source category. The stringent standards based on state-of-the-art control technologies that are currently imposed on coal-fired EGUs have already achieved significant reductions in HAP emissions. As EPA itself noted, the MATS rule has achieved steep reductions in HAP emission levels since 2010, including a 90 percent reduction in mercury, 96 percent reduction in acid gas HAPs, and an 81 percent reduction in non-mercury metal HAPs.[12]

Data from EPA and the U.N Global Mercury Assessment show mercury emissions from U.S. power plants are now so low they accounted for only 0.12 percent of global mercury emissions in 2022, assuming all other sources remained constant at 2018 levels.[13] These data demonstrate that

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[11] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[12] Fact Sheet, *EPA's Proposal to Strengthen and Update the Mercury and Air Toxics Standards for Power Plants,* *https://www.epa.gov/system/files/documents/2023-04/Fact%20Sheet_MATS%20RTR%20Proposed%20Rule.pdf*

[13] United Nations, "Global Mercury Assessment 2018," UN Environment Programme, August 21, 2019, https://wedocs.unep.org/bitstream/handle/20.500.11822/27579/GMA2018.pdf?sequence=1&isAllowed=y

US mercury emissions from power plants are lower than global cremation emissions, and North Dakota coal facilities emitted 9.25 times less mercury in 2021 than global cremations in 2018.[14]

Mercury Emissions Estimates by Sector: 2018 vs U.S. and N.D. Coal Plant Emissions		
Category	**US Tons**	**Percent of Global Emissions**
Artisanal and small-scale mining	921.42	37.68
Global stationary combustion of coal	517.45	21.16
Non-ferrous metals production	359.32	14.69
Cement production	256.48	10.49
Waste from products	161.63	6.61
Vinyl chlorine monomer	64.09	2.62
Biomass burning	57.05	2.33
Ferrous metals production	43.89	1.79
Chlor alkali production	16.66	0.68
Waste incineration	16.44	0.67
Oil refining	15.81	0.65
Stationary combustion of oil and gas	7.84	0.32
Cremation	4.18	0.17
US stationary combustion of coal	2.90	0.12
North Dakota coal combustion	0.46	0.018

As the above chart indicates: the annual mercury emissions from global cremations (where the mercury primarily comes from individuals with dental fillings) exceed the mercury annually emitted by all coal-fired EGUs in the United States combined, and is orders of magnitude more than the mercury emissions from all coal-fired EGUs in North Dakota.[15]

Moreover, the Administrative Record indicates EPA has performed a comprehensive and detailed risk assessment that clearly documents the negligible remaining residual risks posed by the very low amount of HAPs now being emitted by coal-fired EGUs. EPA first performed that risk assessment in 2020, which concluded that "both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of

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[14] ERM Sustainability Initiative, "Benchmarking Air Emissions of the 100 Largest Power Producers in the United States," Interactive Tool, accessed February 29, 2024, https://www.sustainability.com/thinking/benchmarking-air-emissions-100-largest-us-power-producers/

[15] UN Environmental Programme. (2018). Global Mercury Report 2018, Technical Background Report to the Global Mercury Assessment. https://www.unenvironment.org/resources/publication/global-mercury-assessment-technical-background-report

acceptability" for protecting public health with an adequate margin of safety.[16] Similarly, EPA's risk assessment supports the conclusion that residual risks of HAP emissions from the EGU source category are "acceptable" for other potential public health effects, including both chronic and acute non-cancer effects.[17]

These conclusions have been confirmed by the detailed reevaluation of the 2020 risk assessment that the Agency is now completing as part of the current rule-making action. That EPA reevaluation clearly demonstrates that the 2020 risk assessment did not contain any significant methodological or factual errors that could call into question the results and conclusions reached in the 2020 risk assessment. Most notably, EPA used well-accepted approaches and methodologies for performing a residual risk analysis that adhere to the requirements of the statute and are consistent with prior residual risk assessments performed by EPA over the years for other industry sectors.[18]

The results from both residual risk assessments can lead to only one rational conclusion: the current MATS limitations provide an ample margin of safety to protect public health in accordance with CAA section 112.

The DEQ filed comments addressing these points and asking EPA to provide a better health benefit justification than the rationale currently included in the Regulatory Impacts Analysis (RIA).[19] In particular, DEQ noted that EPA cannot rely on non-HAPs' co-benefits to justify the Proposed Rule, and EPA has not identified any HAP-related benefits that would be sufficient to justify the Proposed Rule. The agency also voiced skepticism over what it called EPA' s suspect characterization of the health benefits that it identified, which is quoted below:

> While the screening analysis that EPA completed suggests that exposures associated with mercury emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers.[20]

DEQ's well-founded concern is that EPA's admission that current exposure associated with mercury is below levels of concern is directly inconsistent with, not support of, EPA's proposal for a lower standard.

DEQ commented that this theme, unfortunately, is consistent across the entire "Benefits Analysis" section of the RIA, citing another example of this inconsistency, which is quoted below:

> "Regarding the potential benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively

[16] 88 Fed. Reg. at 24,865.
[17] *Id*. at 24,865-66.
[18] 88 Fed. Reg. at 24,865.
[19] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.
[20] *Id.* At p. 0-8.

> ....Overall, the uncertainty associated with modeling potential of benefits of mercury reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates-though importantly such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including methylmercury exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-mercury metal HAP were not expected to exceed acceptable levels, although we note that these emissions reductions should result in decreased exposure to HAP for individuals living near these facilities."[21]

Comments filed by the Lignite Energy Council (LEC) further emphasize the point. LEC stated that according to the risk review EPA conducted in 2020, which EPA has proposed to reaffirm, the risks from current emissions of hazardous air pollutants (HAP) emitted by coal-fired power plants are several orders of magnitude below what EPA deems sufficient to satisfy the Clean Air Act.[22] LEC points out that EPA has for decades found risks to be acceptable with an ample margin of safety if maximum individual excess cancer risks presented by any single facility is less than "100-in-1 million." In comparison, EPA's analysis of the coal- and oil-fired electric utility source category recognizes the risk it presents is now at one tenth of that acceptable level, with a maximum risk from any individual facility of "9-in-1 million."

However, even that value vastly overstates the risk associated with coal-fired power plants. The "9-in-1 million" risk level identified by EPA is only associated with a single, uncontrolled, residual oil-fired facility located in Puerto Rico.[23] What EPA's discussion of risk fails to recognize, but its analysis clearly shows, is that the highest level of risk presented by any coal-fired power plant is actually "0.3-in-1 million," more than 300 times lower than the threshold EPA deems acceptable.[24]

The level of risk presented by North Dakota lignite-powered plants is lower still. According to EPA's risk review, the maximum risks presented by any North Dakota lignite-fired power plant is "0.08-in-1 million," yet another order of magnitude lower than the highest risk from any coal-fired plant, and more than three orders of magnitude lower than EPA's "acceptable" level of risk with an "ample margin of safety."

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[21] *Id.* at pp. 4-1 - 4-2.

[22] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[23] *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, Docket ID No. EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019) ("Risk Assessment") (note that Table 2a is printed upside down in the final September 2019 version of the Residual Risk Assessment posted at www.regulations.gov, which may interfere with search commands; a searchable version of the same table is available in the December 2018 draft version, Docket ID No.). *See also* 84 Fed. Reg. at 2699 ("There are only 4 facilities in the source category with cancer risk at or above 1-in-1 million, and all of them are located in Puerto Rico.").

[24] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

The risks from North Dakota lignite are so low that they are more easily expressed, not in a million, but in a ***billion***—EPA has determined that the excess cancer risks from all North Dakota lignite plants fall between 5- and 80-in-1 billion.[25] Moreover, EPA's analysis indicates that those maximum risks are not associated with mercury.[26]

In fact, EPA's own analysis confirms the risks from North Dakota lignite-powered plants are so low they are little more than a rounding error that does not even qualify as a significant digit. In its analysis of the still low but relatively higher risk from the Puerto Rican oil-fired plants, EPA determined that one of those facilities presented a risk no greater than "1-in-1 million," even though EPA's modeling actually returned a risk level of "1.**09**-in-1 million."6 EPA discarded the extra ".09," apparently finding it too small to matter. However, that extra ".09" risk equates to "90-in-1 billion," and it is therefore higher than the ***entire*** risk identified for any North Dakota lignite plant.

The Administrative Record Indicates the Mercury Standard of 1.2 lb./TBtu is Technically Unachievable for EGUs using North Dakota Lignite Coal

The Administrative Record for the proposed rule suggests EPA made numerous critical mistakes in assuming lignite fired EGUs can achieve a 1.2 Hg/lb limit with 90% Hg removal. As detailed in the Cichanowicz Report, Section 6, EPA assumed the characteristics of lignite and subbituminous coals are similar such that the Hg removal by emission controls capabilities is similar. In this light, EPA did not consider that the high presence of sulfur trioxide (SO3) in lignite coal combustion flue gas that significantly limits the Hg emissions reduction potential of emissions controls.[27]

Similarly, as noted by LEC, EPA's proposal references data obtained via an information collection request as indicative of the level of performance achievable at North Dakota lignite facilities, but that data only reflects relatively short-term testing that does not fully capture the significant variability of lignite coals. Also, unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, all North Dakota lignite units are located at mine-mouth facilities without access to other coal types, and therefore depend entirely on the fuel extracted from the neighboring mine. As a result, changes in constituents between seams of lignite coal can result in a high level of variability in the emission rates that result from use of the coal as it is mined over time.[28]

While LEC agreed with EPA that the injection of activated carbon is the most effective means of reducing mercury emissions from lignite-powered units, LEC also criticized EPA for ignoring the well-known diminishing returns of injecting more carbon. With each marginal increase in carbon

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[25] Risk Assessment, Tbl. 2a (indicating cancer risks of 8.07e-08, 3.09e-08, 1.31e-08, 1.21e-08, and 5.12e-09 for Facility NEI IDs 380578086511, 380578086311, 380558011011, 380578086511, 380578086611 (Milton R. Young, Leland Olds, Coal Creek, Antelope Valley, and Coyote).

[26] *Id*., at Tbl. 2a (indicating the target organ of the risk associated with the plants identified in note 5 is "respiratory").

[27] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[28] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

injection, the incremental increase in emission reduction capability falls. Thus, injecting more and more carbon will not necessarily result in greater emission reductions beyond a certain injection level. LEC asked EPA to evaluate the effect of diminishing returns on its conclusion that North Dakota lignite-powered facilities can achieve the standard designed for all other units of 1.2 lb/TBtu.

EPA does not appear to have taken the above concerns into account in claiming lignite- powered facilities can achieve the performance levels achieved at subbituminous plants. As a result, EPA has significantly underestimated the level of control needed to achieve the proposed standard of 1.2 lb/TBtu. Contrary to the analysis EPA relies upon to justify lowering the standard for lignite plants, control efficiencies of greater than 90 percent would be needed for North Dakota lignite-powered facilities.[29] LEC's comments asked EPA to reconsider its proposal in light of these concerns, and in light of EPA's legal obligation to ensure all standards are "achievable," which means they "must be capable of being met under most adverse conditions which can reasonably be expected to recur."[30]

The Administrative Record indicates a key reason why EPA's proposed standards are unachievable is the chemical composition of North Dakota lignite. For example, lignite has different heat and moisture content than subbituminous coals. As a result, a greater volume of fuel and air is needed at lignite plants to produce the same heat input compared to subbituminous plants. Due to higher fuel and air flows, a much greater volume of sorbent is needed to achieve similar emission reductions, and the additional sorbent dramatically increases cost, and therefore reduces the cost-effectiveness, of the controls.[31]

Another distinguishing difference EPA appeared to overlook in its proposal is the higher sulfur concentration in North Dakota lignite relative to subbituminous Powder River Basin coal, which in turn produces a higher level of sulfur trioxide ("SO3"). In the past, EPA has worked with a consultant that recognized this reality as follow:

> With flue gas SO3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.[32]

Cichanowicz et al. highlighted this passage from the S&L technology assessment and also noted that the presence of SO3 often affects capture rates in another way—by requiring units with measurable SO3 to be designed with higher gas temperature at the air heater exit to avoid corrosion that would otherwise occur if the SO3 is allowed to cool and condense on equipment

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[29] Cichanowicz Report, at 25, Table 6-1.

[30] *White Stallion Energy Center, LLC v. EPA*, 748 F.3d 1222, 1251 (2014) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n. 46 (D.C. Cir.1980)).

[31] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[32] Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology*, Project 12847-002, at 3 (Mar. 2013).

components. However, that higher exit gas temperature also impacts the effectiveness of sorbent injection systems—special-purpose tests on a fabric filter pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[33] The higher levels of SO_3 formed by the higher sulfur content found in lignite fuels will inhibit the ability of injected sorbents to reduce mercury emissions at lignite plants to a far greater extent than at subbituminous plants.

LEC agreed with these concerns in its comments and raised another important consideration — the fact that, unlike subbituminous plants, selective catalytic reduction (SCR) is technically infeasible on North Dakota lignite, due to its chemical composition. Although SCR systems are primarily installed for the control of nitrogen oxides (NO_X), SCR can enhance the oxidation of elemental mercury ("Hg^0") which facilitates removal in downstream control equipment, such as wet flue gas desulfurization (FGD) systems.[34] The higher level of mercury control achievable with an SCR is almost certainly why the one lignite plant (Oak Grove) evaluated by EPA as part of its review of the MATS RTR appears capable of achieving the mercury limit set for other coal ranks—it has an SCR that cannot be installed on North Dakota lignite facilities.[35]

LEC's comments also highlighted the experience of two LEC members that recently evaluated the difference in mercury control achieved by plants using subbituminous coal equipped with an SCR and plants using lignite coal without an SCR. Based on those evaluations, North Dakota lignite-powered facilities were found to have much greater difficulty reducing mercury emissions, despite using more than three times the amount of halogenated activated carbon than the subbituminous plant.

In the past, EPA has questioned whether SCR is technically feasible for North Dakota lignite-powered facilities, and recent research has confirmed that the significant challenges associated with using SCR on North Dakota lignite remain unresolved.[36] Although SCR has been demonstrated on the types of lignite found in other parts of the country, North Dakota lignite differs substantially in chemical makeup because it contains a much higher concentration of alkali metals (*e.g.*, sodium and potassium) that render the catalyst ineffective.[37]

In particular, the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 µm. As a vapor or as a very small particle, the sodium will pass through any upstream emissions control equipment (*e.g.*, electrostatic precipitators and scrubbers), and thus will reach the SCR regardless of whether the SCR is located before other emission control devices (high-dust configuration) or after those other controls (low-dust or tail-end configurations).[38]

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[33] Sjostrom 2016.

[34] 88 Fed. Reg. at 24875.

[35] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[36] *See* Draft SIP, App. D, at D.2.c-5 (citing Benson, Schulte, Patwardhan, Jones (2021) "The Formation and Fate of Aerosols in Combustion Systems for SCR NO_X Control Strategies" A&WMA's 114th Annual Conference, #983723).

[37] *Id.*

[38] *Id.*

Once the sodium particles reach the SCR, they plug the pores of the catalyst, which are the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive. Recent efforts to address these concerns through either cleaning or regeneration of the catalyst have not been successful, even at pilot scale. A study recently cited by DEQ in its regional haze plan provides additional details on these efforts and the unsolved technical challenges that remain regarding the impact of alkali metals in North Dakota lignite on the technical feasibility of SCR.[39]

According to LEC, its members report that efforts to identify a willing vendor for an SCR on a North Dakota lignite unit have been unsuccessful—all vendors have declined to offer SCR for use on North Dakota lignite once they have closely reviewed the unique characteristics that make SCR infeasible on that particular fuel.[40]

In short, the Administrative Record and other available evidence indicates that North Dakota lignite-powered facilities will likely not be able to meet the revised emission standards EPA is proposing for the MATS Rule.

The Administrative Record Indicates the Lower PM Standard May Also Not Be Technically Feasible

In addition to imposing a more stringent mercury standard on lignite by essentially eliminating the subcategory, EPA's proposal also lowers the standard on fPM for all existing units to the level previously deemed achievable only by new units. However, like its proposed Hg standard for lignite, EPA's proposal to revise the PM standard for all coal types remains unjustified by any demonstration of potential human health or environmental benefits.

The LEC's comments detail particular concerns associated with EPA's failure to provide a reasonable justification for so dramatically reducing the PM limit.[41] As LEC noted, the risks that the MATS Rule is designed to address have already been eliminated, down to several orders of magnitude below the level at which Congress directed EPA to stop regulating. The highest residual risk for the entire source category, which is based on an oil-fired unit, is just one tenth of EPA's acceptable level of risk, and the highest risk from any coal plant is more than an order of magnitude below the risk presented by oil-fired units.

Furthermore, the Administrative Record suggests that EPA's analysis of the achievability of the new 0.01 lb/mmBtu standard is based on an arbitrary data set, and that analysis also suffers from a lack of transparency. Specifically, commenters observed that EPA relies on a Sargent & Lundy memorandum that lacks sufficient detail or supporting documentation to verify the assumptions made, essentially hiding much of the agency's thought process behind the claim that the

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[39] *Id.*

[40] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[41] *Id.*

information on which it is based is not available in public forums.[42] In doing so, EPA seemingly commits what it has previously cited as error in plans developed by states and industry—failing to provide sufficient information to understand the reasoning underlying key conclusions.[43]

Moreover, the Administrative Record indicates the combined effect of both the proposal to require universal use of CEMS and the lower standard of 0.01 lb/mmBtu will present a compounded challenge if finalized as proposed. Commenters indicated that the difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate CEMS, and the difficulty in using CEMS will be exacerbated by the dramatically lower standard.[44] In particular, serious concerns remain with respect to whether a fPM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a CEMS to differentiate compliance from a false reading.[45] EPA attempts to allay these fears by claiming existing units can simply follow in the footsteps of new units, since new units have been subject to a CEMS requirement with a fPM emission limit of 0.090 lb/megawatt-hour since the inception of MATS.[46] **But that assurance provides no comfort—there are no new units.[47]**

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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

Power Plant Economic Impacts

The economic impacts for a lignite power plant from the Mercury and Air Toxics Standards (MATS) finalized rule can be substantial. The updated MATS rule, if implemented by the

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[42] *PM Incremental Improvement Memo*, Doc. ID EPA-HQ-OAR-2018-0794-5836 (March 2023) ("Improvements to existing particulate control devices will be dependent on a range of factors including the design and current operation of the units, which is not documented in public forums. … Unfortunately, the details of how those units' ESP designs, upgrades, and operation are not publicly available …. In order to evaluate the applicability of one or more of these potential improvements, information would need to be known about the existing ESPs and their respective operation which is not documented in public forums.").

[43] *See, e.g., Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan*, 82 Fed. Reg. 32,294, 32,298 (July 13, 2017) ("Entergy's DSI and scrubber cost calculations were based on a propriety [sic] database, so we were unable to verify any of the company's costs. … Because of these issues, we developed our own control cost analyses ….").

[44] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[45] *Id.*

[46] 88 Fed. Reg. at 24874. The electrical output-based limit for new EGUs translates to approximately 0.009 lb/mmBtu, which is slightly below EPA's proposed limit of 0.010 lb/mmBtu.

[47] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

Environmental Protection Agency (EPA), aims to reduce mercury and other hazardous air pollutant emissions from coal-fired power plants. Coal-firing power plants, and lignite-firing power plants in particular, may face specific challenges and economic consequences in complying with these regulations, which could result in their forced retirement. Some potential economic impacts include:

1. **Escalating Operational Expenditures:** Under this rule, lignite power plants will face an excessive economic burden from a significant uptick in operational costs due to the integration of pollution control equipment. The installation of advanced technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates continuous monitoring and maintenance to ensure optimal performance. Design specifications vary from plant to plant which increases the complexities of the operating systems that require regular cleaning, replacement of consumables, and calibration, all of which incur additional expenses. Moreover, the implementation of pollution control, measures may necessitate alterations in combustion processes or the introduction of supplementary fuel, further driving up operational costs. As a result, lignite power plants are burdened with substantial ongoing expenditures, while also lacking a positive cost benefit analysis, which will undermine their economic viability and competitiveness in the energy market**.**

2. **Dilemma of Plant Retrofitting or Retirement:** Lignite power plants are confronted with the challenging prospect of either retrofitting existing facilities or contemplating retirement in response to the stringent requirements of the Mercury and Air Toxics Standards (MATS). Plant retrofitting involves substantial investment in upgrading equipment and implementing advanced pollution control technologies to achieve compliance with regulatory mandates. However, these retrofitting endeavors entail significant additional costs, potentially straining the financial resources of plant owners and operators. Moreover, the uncertainty surrounding the long-term economic viability of retrofitted plants further complicates decision-making processes**.**

3. **Impact on Electricity Prices:** The implementation of pollution control technologies to comply with MATS regulations can impose significant financial burdens on lignite power plants. These costs, encompassing the installation, maintenance, and operation of such technologies, would ultimately be transferred to consumers in the form of higher electricity prices. As power plants seek to recoup the expenses incurred in meeting regulatory requirements, consumers will experience an uptick in their electricity bills. This escalation in electricity prices will have far-reaching implications for households, businesses, and industries reliant on affordable energy. It will affect household budgets, impact the competitiveness of businesses, and influence consumer spending patterns. Additionally, higher electricity prices will introduce challenges for industries sensitive to energy costs, potentially leading to shifts in production, investment, and employment patterns within the broader economy. Therefore, the economic impact of elevated electricity prices resulting

from MATS compliance should be carefully considered within the context of the energy market, taking into account the implications for consumers, businesses, and overall economic growth.

4. **Employment Effects:** The escalation in costs and the possibility of plant retrofitting or retirement can reverberate through the lignite industry and associated sectors, potentially leading to job losses. As lignite power plants grapple with increased operational expenses and the financial strain of compliance with regulatory requirements, they may be compelled to streamline operations or even cease production altogether. Such decisions can have a ripple effect on employment within the community, impacting not only plant workers but also individuals employed in ancillary industries such as mining, transportation, and manufacturing. Job losses in these sectors can contribute to economic challenges, including reduced consumer spending, increased unemployment rates, and a decline in overall economic activity. Furthermore, the social and psychological impacts of job loss on affected individuals and communities cannot be understated, as they may face financial insecurity, stress, and uncertainty about their future prospects. Therefore, the potential job impacts stemming from increased costs and plant adjustments underscore the broader economic implications of regulatory compliance measures in the lignite industry.

5. **Regional Economic Consequences:** Lignite power plants are often linchpins of regional economies, exerting substantial influence on employment, tax revenue, and economic activity. Any shifts in the economic viability of these plants, whether due to increased costs, regulatory compliance burdens, or operational adjustments, will trigger broader consequences for local economies. The potential closure or downsizing of lignite power plants can result in the loss of direct and indirect employment opportunities, affecting not only plant workers but also individuals and businesses reliant on plant-related activities. Moreover, the decline in plant operations will lead to reduced tax revenue for local governments, impacting their ability to fund essential services and infrastructure projects. Additionally, the loss of economic activity associated with lignite power plants will ripple through the supply chain, affecting suppliers, vendors, and service providers in the region. This domino effect will exacerbate economic challenges, including decreased consumer spending, increased business closures, and a general downturn in economic vitality. Therefore, changes in the economic landscape of the lignite industry will have far-reaching consequences for regional economies, underscoring the interconnectedness between energy production, employment, and overall economic well-being at the local level.

6. **Impact on Investment Decisions:** The economic ramifications of the MATS rule can significantly shape investment decisions within the lignite industry. Plant owners and prospective investors must carefully evaluate the long-term economic feasibility and potential returns on investment in light of stringent regulatory compliance mandates. The substantial costs associated with MATS compliance, including technology upgrades and operational adjustments, may deter investment in lignite power plants or prompt

divestment from existing assets. Investors may reassess the risk-return profile of lignite-related ventures, considering factors such as regulatory uncertainty, market volatility, and shifting energy trends. Moreover, the potential for increased operational costs and regulatory burdens may incentivize investment in alternative energy sources or cleaner technologies, which align more closely with evolving environmental and sustainability objectives. Therefore, the economic implications of the MATS rule play a pivotal role in shaping investment decisions within the lignite industry, influencing capital allocation, project planning, and strategic resource allocation strategies.

7. **Legal and Regulatory Costs:** Meeting MATS requirements often entails significant legal and regulatory costs associated with monitoring, reporting, and ensuring continued compliance. Lignite power plants must allocate resources to navigate complex regulatory frameworks, engage legal counsel, and implement robust monitoring and reporting systems to adhere to emissions standards. These additional expenses contribute to the overall economic strain on lignite power plants, exacerbating the financial challenges associated with regulatory compliance. As a result, the burden of legal and regulatory costs further underscores the financial pressures faced by lignite power plant operators, shaping their strategic decision-making and resource allocation efforts.

Grid Reliability Impacts

Compliance with the Mercury and Air Toxics Standards (MATS) rule will likely have grid reliability impacts on regional power grids that rely on lignite- or other coal-firing power plants. The impacts on grid reliability for power grids that rely on lignite- or other coal-firing power plants can include:

1. **Operational Adaptations and Flexibility Constraints**: The implementation of pollution control technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates operational modifications within lignite power plants. These adjustments may include alterations to combustion processes, fuel handling procedures, and overall plant operations to accommodate the integration of new equipment and systems. However, such operational changes can compromise the inherent flexibility of lignite power plants to respond effectively to fluctuating load conditions and grid demands. The need for continuous operation of pollution control systems, coupled with potential limitations in responsiveness, may impede the plant's ability to ramp up or down quickly in response to changes in electricity demand or supply. Consequently, the reliability of lignite power plants to maintain grid stability and meet grid operator requirements may be compromised, raising concerns about their ability to ensure consistent and secure electricity supply. Thus, while MATS compliance aims to mitigate environmental impacts, the operational adaptations required may introduce challenges to the reliability and flexibility of lignite power plants in supporting a resilient and dynamic energy grid.

2. **Disruptions Due to Equipment Installation**: The installation and retrofitting of pollution control equipment often necessitate temporary shutdowns or reduced operating capacities within lignite power plants. These planned downtime periods are essential for integrating new equipment, conducting modifications, and ensuring compliance with regulatory requirements. However, the interruptions in plant operations during these installation phases will have adverse effects on the overall reliability and availability of the plant. The temporary cessation of power generation activities will disrupt electricity supply, potentially affecting grid stability and reliability. Moreover, extended downtime periods may lead to revenue losses for plant operators and suppliers, as well as inconvenience for consumers and end-users reliant on consistent electricity provision. Therefore, while essential for achieving compliance with MATS regulations, the equipment installation process poses challenges to the reliability and continuity of lignite power plant operations, emphasizing the importance of efficient planning and management to minimize disruptions.

3. **Efficiency Implications**: The introduction of pollution control technologies, especially those targeting mercury emissions reduction, will potentially undermine the overall efficiency of lignite power plants. While these technologies play a crucial role in meeting regulatory standards, they often require additional energy inputs and introduce operational complexities that can compromise plant efficiency. For instance, activated carbon injection (ACI) systems necessitate the injection of powdered carbon into the flue gas stream, which can increase resistance and pressure drops within the system, thus reducing overall efficiency. Similarly, flue gas desulfurization (FGD) systems require energy-intensive processes such as limestone slurry preparation and circulation, further impacting plant efficiency. The reduction in efficiency can translate to decreased electricity output per unit of fuel input, potentially affecting the plant's ability to generate electricity reliably and meet demand fluctuations. Consequently, while pollution control measures are essential for environmental protection, the associated efficiency implications underscore the need for careful optimization and balancing of environmental and operational considerations to ensure reliable power generation from lignite plants.

4. **Elevated Maintenance Demands**: The incorporation of MATS-compliant equipment, including ACI and FGD systems, often translates to heightened maintenance requirements within lignite power plants. The intricate nature of these pollution control technologies necessitates more frequent inspections, cleaning, and servicing to ensure optimal performance and regulatory compliance. However, the increased maintenance needs can result in extended periods of downtime, during which the plant may be unable to generate electricity, impacting its reliability and availability. Moreover, the allocation of resources and manpower to address maintenance tasks diverts attention and resources away from other operational activities, potentially affecting overall plant efficiency and productivity. Therefore, while essential for environmental compliance, the elevated maintenance

demands associated with MATS-compliant equipment pose challenges to the reliability and operational continuity of lignite power plants, highlighting the importance of proactive maintenance planning and execution to minimize disruptions.

5. **Inherent Fuel Supply Hurdles:** Lignite power plants grapple with inherent challenges associated with the utilization of lignite coal, particularly in meeting stringent emission standards. Lignite, characterized by its lower rank and elevated moisture content, poses unique obstacles in combustion processes. The variability in chemical composition across different seams of coal extracted from mines further complicates the task of ensuring consistent and efficient combustion. Each seam presents distinct combustion characteristics, necessitating meticulous adjustments in operational parameters to maintain compliance with emission regulations. Consequently, lignite power plants encounter difficulties in securing a reliable and uniform fuel supply, which undermines their ability to consistently meet emission targets and operational efficiency goals. The intricacies of managing diverse coal qualities exacerbate the complexities of pollution control measures, posing significant operational challenges for lignite power plants.

6. **Integration Challenges**: The introduction of new pollution control technologies into operational lignite power plants may encounter compatibility hurdles. Ensuring seamless integration with existing infrastructure is paramount for preserving reliability. Compatibility issues can emerge from differences in technology specifications, operational parameters, or control systems between the new equipment and the plant's established infrastructure. Unaddressed disparities may lead to operational inefficiencies, malfunctions, or system failures. Thus, meticulous planning and coordination are vital to mitigate compatibility risks and uphold the reliability of lignite power plants. Failure to address these challenges will compromise plant performance, emphasizing the need for thorough assessment and integration procedures when adopting new technologies.

7. **System Coordination and Grid Stability:** Adjustments in operating conditions and responses to fluctuating load demands can disrupt system coordination and compromise grid stability. Lignite power plants must coordinate closely with grid operators to maintain reliable electricity supply while adhering to MATS requirements. Changes in plant operations, such as implementing pollution control technologies or adjusting output levels, can affect the overall balance of supply and demand within the grid. Without effective coordination, these changes may lead to imbalances, voltage fluctuations, or frequency deviations, posing risks to grid stability. Therefore, robust communication and collaboration between lignite power plants and grid operators are essential to ensure seamless integration of plant operations with broader grid dynamics. By coordinating effectively, lignite power plants can contribute to grid stability while meeting regulatory obligations, ensuring the reliable delivery of electricity to consumers.

8. **Continuous Compliance Management**: Adhering to emission limits mandated by MATS necessitates ongoing monitoring and fine-tuning of pollution control equipment. The chemical properties of lignite can vary even within coal seams from the same mine, posing challenges in preparation and adjustment for plant operations. This variability complicates efforts to maintain consistent compliance, requiring dynamic adjustments in day-to-day plant operations. Consequently, ensuring reliable compliance becomes a dynamic process, demanding meticulous attention to detail and proactive management of pollution control systems. Consistent monitoring and adjustment are essential to mitigate emissions effectively while sustaining the operational reliability of lignite power plants amidst the inherent variability of lignite coal properties.

9. **Supply Chain Vulnerabilities:** The consolidation in the power plant equipment sector over the past decade has reduced the number of suppliers available. Relying on specific suppliers for pollution control equipment and technologies introduces supply chain risks. Disruptions in the supply chain, such as shortages, delays, or quality issues, will impede the timely installation and operation of essential equipment, jeopardizing reliability. Lignite power plants must carefully assess and manage these supply chain vulnerabilities to ensure uninterrupted access to critical components and technologies necessary for regulatory compliance and operational integrity. Proactive measures, such as diversifying suppliers or implementing contingency plans, are crucial for mitigating supply chain risks and maintaining the reliability of lignite power plants.

10. **Long-Term Viability and Aging Infrastructure:** Compliance with MATS regulations will raise concerns about the long-term viability of older lignite power plants. Aging infrastructure may struggle to adapt to the requirements of new pollution control technologies, posing challenges that will impact reliability. The integration of these technologies into outdated systems may require extensive retrofitting or upgrades, which can strain resources and prolong downtime. Moreover, the operational lifespan of aging infrastructure may be limited, leading to questions about the economic feasibility of investing in costly compliance measures. Plant owners must carefully assess the cost-benefit ratio of compliance efforts and consider the potential impact on reliability when evaluating the long-term viability of older lignite power plants. Failure to address these challenges will compromise the reliability and competitiveness of these facilities in the evolving energy landscape.

Section D: Modeling Results

Summary

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case, instead it conducted a Resource Adequacy and reserve margin analysis, which EPA has claimed is necessary but not sufficient to grid reliability.[48]

EPA's lack of reliability modeling prompted several entities to voice concerns in the original docket for the Proposed MATS rule would negatively impact grid reliability, including the National Rural Electric Coop Association, the American Coal Council, The Lignite Energy Council, PGen, the American Public Power Association, and the National Mining Association.[49,50,51,52,53,54]

To provide this necessary perspective, Center of the American Experiment modeled the reliability and cost impacts of the proposed Mercury and Air Toxics Standards (MATS) in the subregions consisting of the Midcontinent Independent Systems Operator (MISO) as it relates to the elimination of the subcategory for lignite-fired power plants.[55,]

Our analysis determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system if these resources are replaced with wind, solar, battery storage, and natural gas plants consistent with the EPA's estimates for capacity values for intermittent and thermal resources.

Building these replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035, resulting in incremental costs of $1.9 billion in the Partial

[48] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[49] NRECA Comments, EPA-HQ-OAR-2018-0794-5956, at 5-6.
[50] American Coal Council Comments, EPA-HQ-OAR-2018-0794-6808, at 3.
[51] LEC Comments, EPA-HQ-OAR-2018-0794-5957, at 17.
[52] PGen Comments, EPA-HQ-OAR-2018-0794-5994, at 5.
[53] APPA Comments, EPA-HQ-OAR-2018-0794-5958, at 33.
[54] NMA Comments, EPA-HQ-OAR-2018-0794-5986, at 29.
[55] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.

scenario and \$3.8 billion in the Full scenario through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts, which can result in food spoilage, property damage, lost labor productivity, and loss of life. American Experiment calculated the economic damages associated with the increase in unserved electricity demand using a metric called the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Our analysis found that the MATS rule would cause an additional 73,699 additional megawatt hours (MWh) of unserved load in the in the Full MATS Retirement scenario in 2035 using 2019 hourly electricity demand and wind and solar capacity factors. Using a conservative value for the VoLL of \$14,250 per MWh, we conclude the MATS rule would produce economic damages of \$1.05 billion under these conditions.

Therefore, the incremental costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO under the Full scenario exceeds the projected net present value benefits of \$3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.

Modeling the Reliability and Cost of the MISO Generating Fleet Under Three Scenarios

Our analysis examined the impact of the proposed MATS rules on the reliability of the MISO system through 2035 by comparing two lignite retirement scenarios to a "Status Quo" scenario that represents "business as usual" that assumes no changes to the generating fleet occur due to the MATS rule, or any other of EPA's pending regulations.[56]

Status Quo scenario: Installed generator capacity assumptions for MISO in the Status Quo scenario are based on announced retirements from U.S. Energy Information Administration (EIA) database and utility Integrated Resource Plans (IRPs) through 2035 compiled by Energy Ventures Analysis on behalf America's Power, a trade association whose sole mission is to advocate at the federal and state levels on behalf of the U.S. coal fleet.[57] This database is also used by the NERC LTRA suggesting it is among the most credible databases available for this analysis.[58] It should be noted that this database leaves considerably more coal and natural gas on its system than the MISO grid EPA assumes will be in service in the coming years in its Proposed Rule Supply Resource

[56] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

[57] America's Power, "Proprietary data base maintained by Energy Ventures Analysis, an energy consultancy with expertise in electric power, natural gas, oil, coal, renewable energy, and environmental policies" Personal Communication, November 3, 2023.

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

Utilization file, meaning our reliability assessment will be more conservative than if we used EPA's capacity projections.

Retired thermal resources in the Status Quo scenario are replaced by solar, wind, battery storage, and natural gas in accordance with the current MISO interconnection queue to maintain resource adequacy based on capacity values given to these generators in EPA's Proposed Rule Supply Resource Utilization file.[59] These capacity values are described in greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.

Partial MATS Retirement scenario: The Partial MATS retirement scenario assumes 1,150 megawatts (MW) of lignite fired capacity in North Dakota is retired in addition to incorporating all of the announced retirements in the Status Quo. This value was chosen because it represents the retirement of one lignite facility in North Dakota that serves the MISO market. These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[60]

Full MATS scenario: The Full MATS retirement scenario assumes the MATS regulations will cause all 2,264 MW of lignite-fired generators in the MISO system to retire, in addition to incorporating the retirements in the Status Quo scenario will occur.[61] These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[62]

Reliability in each scenario

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case. Instead, it conducted a Resource Adequacy analysis of its proposed rule, compared to the Post IRA base case.

Resource Adequacy and reserve margin analyses can be useful tools for determining resource adequacy and reliability, but the shift away from dispatchable thermal resources (fossil fuel) toward intermittent resources (wind and solar) increases the complexity and uncertainty in these analyses and makes them increasingly dependent on the quality of the assumptions used to construct capacity accreditations.[63]

[59] U.S. Environmental Protect Agency, "Proposed Regulatory Option," Zip File, https://www.epa.gov/system/files/other-files/2023-04/Proposed%20Regulatory%20Option.zip
[60] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[61] These figures represent the rated summer capacity as indicated by the U.S. Energy Information Administration.
[62] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[63] See Appendix 4: Resource Adequacy in Each Scenario.

This is likely a key reason why EPA has distinguished between resource *adequacy* and resource *reliability* in its Resource Adequacy Technical Support Document for its proposed carbon dioxide regulations on new and existing power plants.[64,65] EPA stated:

> "As used here, the term **resource adequacy** is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while **reliability** includes the ability to deliver the resources to the loads, such that the overall power grid remains stable." **[emphasis added].**" EPA goes on to say that "resource adequacy … is necessary (but not sufficient) for grid reliability.[66]

As the grid becomes more reliant upon non-dispatchable generators with lower reliability values, it is crucial to "stress test" the reliability outcomes of systems that use the EPA's capacity value assumptions in their Resource Adequacy analyses by comparing historic hourly electricity demand and wind and solar capacity factors against installed capacity assumptions in the Status Quo, Partial, and Full scenarios.

We conducted such an analysis by comparing EPA's modeled MISO generation portfolio to the historic hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, and 2022. These data were obtained from the U.S. Energy Information Administration (EIA) Hourly Grid Monitor to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).[67]

For our analysis, hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions. These assumptions are generous to the EPA because they increase the annual output of wind and solar generators to levels that are not generally observed in MISO.

Extent of the Capacity Shortfalls

While our modeling determined that the retirement of lignite facilities had a minimal impact on the number of hours of capacity shortfalls observed in the Partial and Full scenarios, retiring the lignite facilities makes the extent of capacity shortfalls worse.

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[64] EPA did not produce a Resource Adequacy Technical Support Document for the MATS rules.
[65] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.
[66] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[67] U.S. Energy Information Administration, "Hourly Grid Monitor," https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

For example, Figure D-1 shows largest capacity shortfalls in the Status Quo scenario, which occur in 2035 using the 2021 Historical Comparison Year for hourly electricity demand and wind and solar capacity factors.

Each resource's hourly performance is charted in the graph below. Thermal units are assumed to be 100 percent available, which is consistent with EPA's capacity accreditation for these resources, and wind and solar are dispatched as available based on 2021 fluctuations in generation. Blue sections reflect the use of "Load Modifying Resources," which are reductions in electricity consumption by participants in the MISO market.

Purple areas show time periods where the batteries are discharged. These batteries are recharged on January 8th and 9th using the available natural gas and oil-fired generators. Red areas represent periods where all of the resources on the grid are unable to serve load due to low wind and solar output and drained battery storage systems. At its peak, the largest capacity shortfall is 15,731 MW.

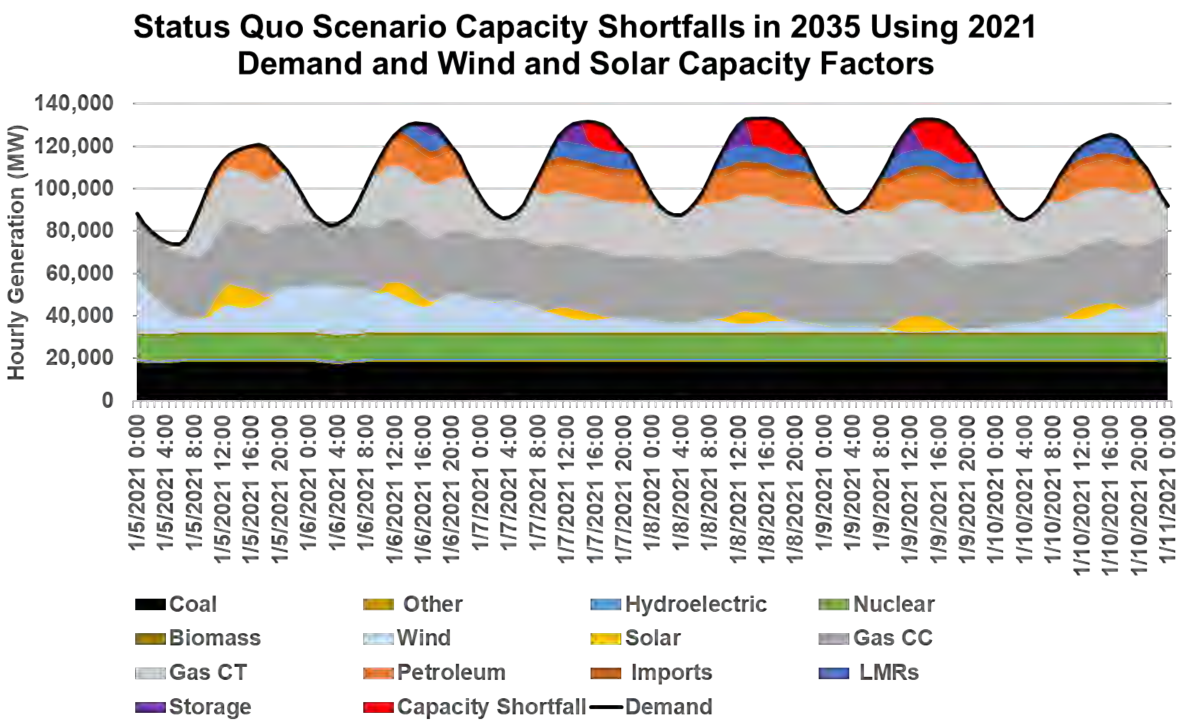

Figure D-1. This figure shows the generation of resources on the MISO grid in the Status Quo during a theoretical week in 2035. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage does not last long enough to avoid blackouts during a wind drought.

These capacity shortfalls become more pronounced in the Partial and Full scenarios as less dispatchable capacity exists on the grid to serve load. Figure D-2 shows the three capacity shortfall events in Figure D-1. It depicts the blackouts observed in the Status Quo scenario in green, and the additional MW of unserved load in the Partial and Full scenarios in yellow and red, respectively.

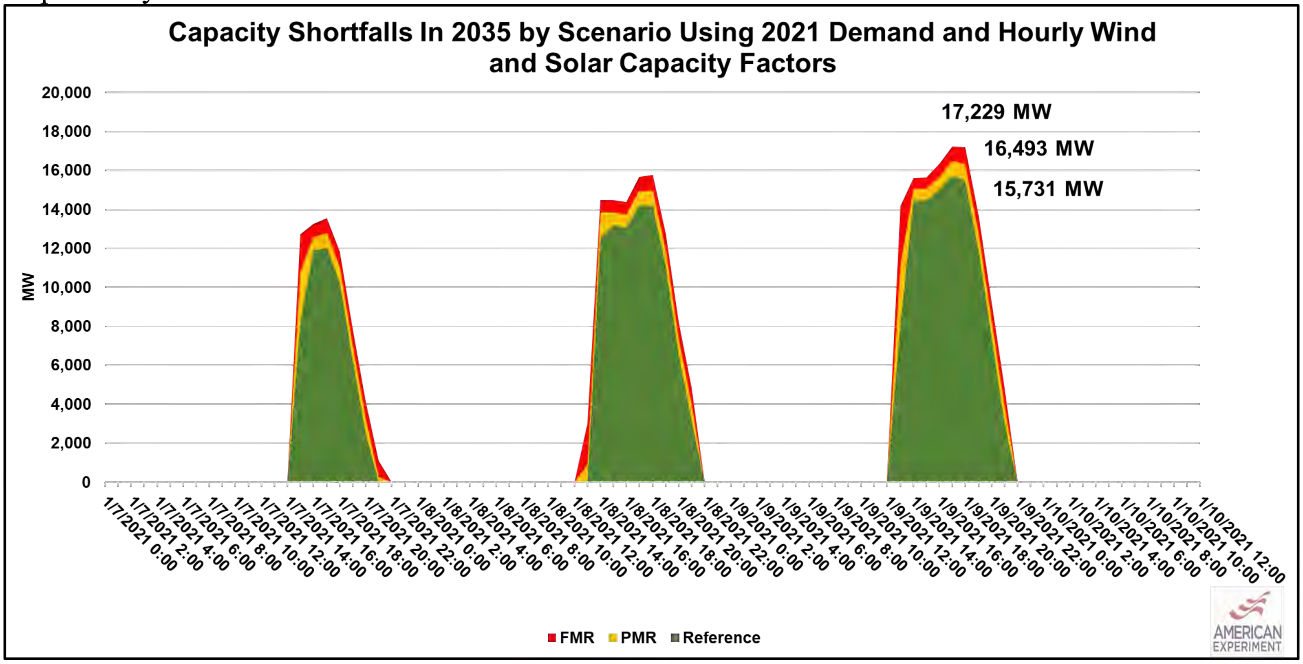

Figure D-2. Capacity shortfalls increase during a hypothetical January 9th, 2035 from 15,731 MW at their peak in the Status Quo to 16,493 MW in the Partial scenario and 17,229 MW in the Full scenario.

Table D-1 shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfall due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

The largest incremental increase in capacity shortfalls would occur in the 2020 HCY in the Full scenario as the blackouts would increase from 552 MW in the Status Quo scenario to 3,295 in the Full scenario, a difference of 2,743 MW.

Maximum MW Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	15,130	15,842	712	16,530	1,400
2020	552	2,587	2,034	3,295	2,743
2021	15,731	16,493	762	17,229	1,498
2022	10,615	11,409	794	12,177	1,562

Table D-1. This table shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfalls due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

It is important to note that this difference is larger than the amount of lignite-fired capacity that is retired in the Full scenario (2,264 MW) because the retirement of these facilities reduces the amount of capacity available to charge battery storage resources.

Unserved MWh in Each Scenario

The amount of unserved load in each scenario can also be measured in megawatt hours (MWh). This metric is a product of the number of hours with insufficient energy resources multiplied by the hourly energy shortfall, measured in MW. This metric may be a more tangible way to understand the impact that the unserved load will have on families, businesses, and the broader economy. Each MWh reflects an increment of time where electric consumers in the MISO grid will not have access to power.

Table D-2 shows the number of MWhs of unserved load in each scenario for the four HCYs studied. In some HCYs, the incremental number of unserved MWhs is fairly small, but in other years they are substantial. In the 2020 HCY, the Partial scenario had 2,042 more MWhs of unserved load than the Status Quo scenario, and the Full scenario had 4,265 MWh of additional unserved load, compared to the Status Quo Scenario.

Total MWh Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	168,723	204,050	35,327	242,393	73,669
2020	582	2,624	2,042	4,847	4,265
2021	244,743	273,927	29,184	304,021	59,278
2022	53,458	62,223	8,765	71,304	17,846

Table D-2. The incremental MWh of unserved load ranges from 2,042 to 35,327 in the Partial scenario, and from 4,265 to 73,669 in the Full scenario.

In the 2019 HCY, the Partial scenario experienced an additional 35,327 MWh of unserved load and the Full scenario experienced 73,669 MWh of unserved load. These additional MWh of unserved load will impose hardships on families, businesses, and the broader economy.

The Social Cost of Blackouts Using the Value of Lost Load (VoLL)

Blackouts are costly. They frequently result in food spoilage, lost economic activity, and they can also be deadly. Regional grid planners attempt to quantify the cost of blackouts with a metric called the Value of Lost Load (VoLL). The VoLL is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

MISO currently assigns a Value of Lost Load (VOLL) of $3,500 per megawatt hour of unserved load. However, Potomac Economics, the Independent Market Monitor for MISO, recommended a value of $25,000 per MWh for the region.[68] For this study, we used a midpoint value of $14,250 per MWh of unserved load to calculate the social cost of the blackouts under each modeled scenario.

Table D-3 shows the economic damage of blackouts in each scenario in model year 2035 and shows the incremental increase in the VOLL in the Partial and Full scenarios. Incremental VOLL costs are highest using the 2019 HCY where MISO experiences an additional $503.4 million in economic damages due to blackouts in the Partial scenario, and an additional $1.05 billion in the Full scenario.

Value of Lost Load for Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	$2,404,309,657	$2,907,716,665	$503,407,008	$3,454,098,692	$1,049,789,035
2020	$8,296,505	$37,389,117	$29,092,612	$69,074,216	$60,777,712
2021	$3,487,594,170	$3,903,464,847	$415,870,677	$4,332,301,464	$844,707,294
2022	$761,782,023	$886,680,023	$124,898,001	$1,016,083,680	$254,301,657

Table D-3. MISO would experience millions of dollars in additional economic damage if the lignite fired power plants in its footprint are shut down in response to the MATS regulations.

It is important to note that these VOLL figures are not the total estimated cost impacts of blackouts for the MATS regulations. Rather, they are a snapshot of a range of possible outcomes for the year 2035 based on variations in electricity demand and wind and solar productivity.

The VOLL demonstrates harm of the economy in a multitude of ways. For the industrial/commercial sector, direct costs from losing power (and therefore benefits from avoiding power outages) can be (1) opportunity cost of idle resources, (2) production shortfalls / delays, (3) damage to equipment and capital, and (4) any health or safety impacts to employees. There are also indirect or macroeconomic costs to downstream businesses/consumers who might depend on the products from a company who experiences a power outage.[69]

For the residential sector, the direct costs are different. They can include (1) restrictions on activities (e.g. lost leisure time, lost work time, and associated stress), (2) financial costs through property damage (e.g. damage to real estate via bursting pipes, food spoilage), and (3) health and safety issues (e.g. reliance on breathing machines, air filters).[70]

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[68] David B. Patton, "Summary of the 2022 MISO State of the Market Report," Potomac Economics, July 13, 2023, https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf.

[69] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

[70] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

Hours of Capacity Shortfalls

Comparing hourly historic electricity demand and wind and solar output to MISO grid in the Status Quo scenario, our modeling found that MISO would have capacity shortfalls in the 2019, 2021, and 2022 HCYs which can be seen in Table D-4 below.

There would be additional capacity shortfalls in all of the HCYs modeled in the Partial and Full scenarios, where the Partial scenario would experience four additional hours of blackouts in 2019 HCY, one additional hour of blackouts in the 2020 HCY, four additional hours of blackouts in 2021 HCY, and one additional hour of blackouts in the 2022 HCY. In the Full scenario, there would be five additional hours of blackouts in the 2019 HCY, one additional hour of blackouts in the 2020 HCY, eight additional hours in the 2021 HCY, and two additional hours in the 2022 HCY, compared to the Status Quo Scenario.

Hours of Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	28	32	4	33	5
2020	2	3	1	3	1
2021	24	28	4	32	8
2022	13	14	1	15	2

Table D-4. Capacity shortfalls occur in three of the four HCYs in the Status Quo scenario and all four HCYs for the Partial and Full scenarios.

Cost of replacement generation

Our VOLL analysis demonstrates that the MATS rules will cause significant economic harm in MISO by reducing the amount of dispatchable capacity on the grid due to lignite plant closures stemming from the removal of the lignite subcategory.

However, load serving entities (LSEs) will also begin to incur costs as they build replacement generation to maintain resource adequacy if lignite resources are forced to retire in response to the proposed MATS rules. These costs will be passed on to electricity consumers and must be calculated to produce accurate estimates of the true cost of the MATS regulations.

We modeled the cost of the replacement generation under the Status Quoe, Partial and Full scenarios. The cost of the Partial and Full scenarios, when compared to the Status Quo scenario, is used to determine the additional economic burden that the MATS regulations will impose onto MISO electricity customers.

Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035 (see Figure D-3).

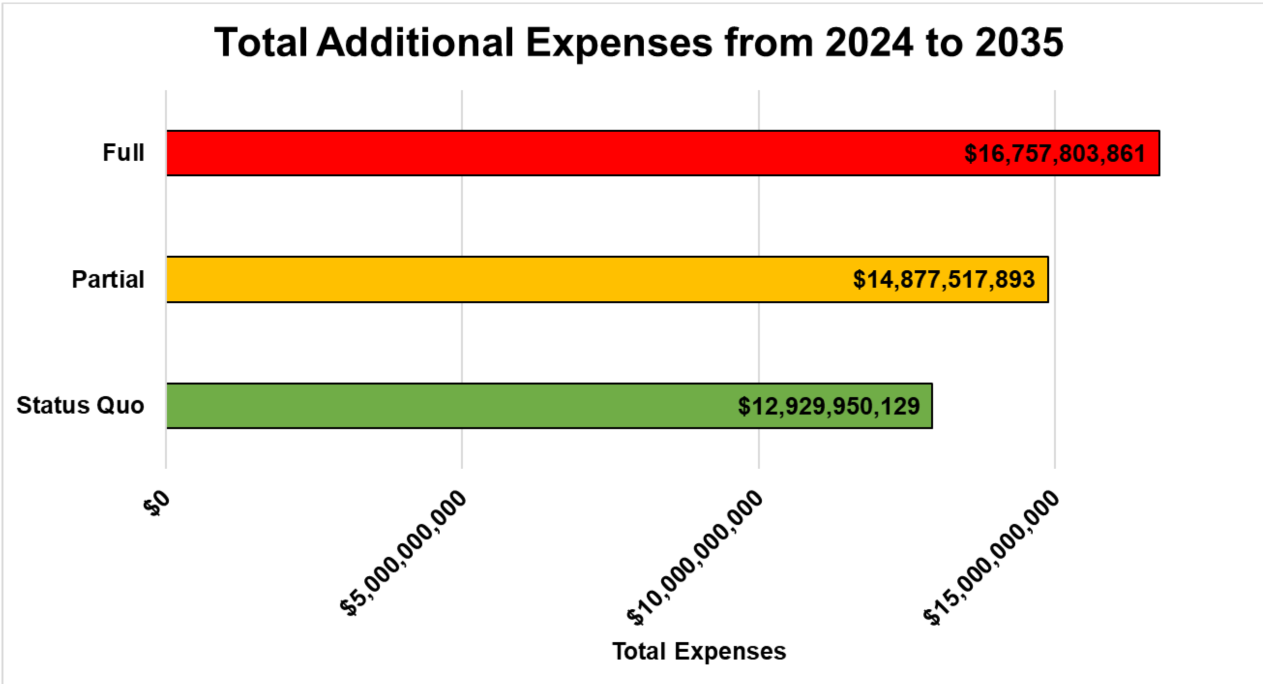

Figure D-3. The Partial scenario will cost $1.95 billion more than the Status Quo scenario from 2024 through 2035 and the Full scenario will cost $3.8 billion more than the Status Quo scenario in this timeframe.

Figure D-4 shows the incremental cost of the Partial and Full scenarios from 2024 through 2030, the period reflecting the up-front costs of complying with the regulations. From 2024 through 2028, LSEs would incur $337 million by building replacement generation in the Partial scenario, compared to the Status Quo scenario, and $654 million in the Full scenario, relative to the Status Quo. It should be noted that these costs are only the cost of building replacement generation and do not factor in the cost of decommissioning or remediating existing power plants or mine sites.

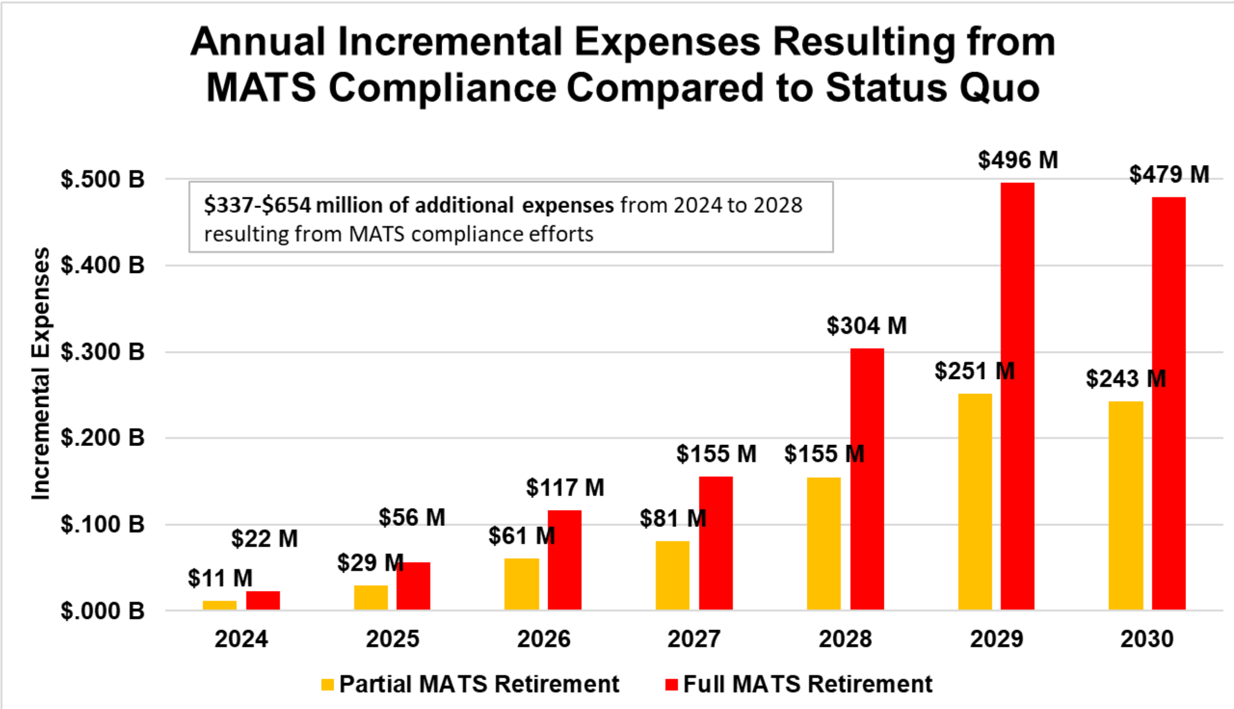

Figure D-4. This figure shows the annual cost of building the replacement capacity needed to maintain resource adequacy after the retirement of the lignite plants based on EPA's capacity accreditation values for wind, solar, storage, and thermal resources.

We describe the total costs of replacement generation capacity for each scenario in greater detail below. The assumptions used to calculate the cost of replacement generation can be found in Appendix 1: Modeling Assumptions.

Status Quo scenario:

The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. These retirements are already projected to occur without imposition of the new MATS Rule or other federal regulations. This retired capacity is replaced with 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.[71]

The total cost of replacement generation for the Status Quo scenario is $12.9 billion. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Status Quo scenario saves $32 billion in fuel costs, $11.5 billion in variable operations and maintenance costs, and $5 billion in taxes. However, these savings are

[71] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

far outweighed by $5.1 billion in additional fixed costs, $16 billion in capital costs, $2.1 billion in transmission costs, and $38.2 billion in utility profits (see Figure D-5).

Figure D-5. The Status Quo scenario saves consumers money from lower fuel costs, fewer variable operations and maintenance costs, and lower taxes (due to federal subsidies) but these savings are outweighed by the additional costs. As a result, building the grid in the Status Quo scenario would increase costs by $12.93 billion compared to today's costs.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.89 cents per kWh in the Status Quo scenario, an increase of nearly 3.5 percent relative to current costs of 9.56 cents per kWh.[72]

Partial MATS Retirement scenario:

The Partial scenario results in the closure of 1,151 MW of lignite capacity and necessitates an incremental increase in replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage, compared to the Status Quo scenario.[73]

The total cost of replacement generation for the Partial scenario is $14.9 billion, and the total incremental cost is $1.9 billion compared to the Status Quo scenario. The majority of these

[72] Annual Electric Power Industry Report, Form EIA-861 detailed data files, https://www.eia.gov/electricity/data/eia861/.
[73] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Partial scenario saves $32.7 billion in fuel costs, $11.6 billion in variable operations and maintenance costs, and $5.1 billion in taxes. However, these savings are far outweighed by $5.3 billion in additional fixed costs, $17.1 billion in capital costs, $2.2 billion in transmission costs, and $39.7 billion in utility profits (see Figure D-6).

Figure D-6. The Partial scenario results in an $14.88 billion in additional costs compared to the current grid due to additional capital costs, fixed operations and maintenance costs, additional transmission costs, and additional utility profits.

Compared to the Status Quo scenario, the incremental savings are $664 million in fuel costs, $119.7 million in variable operations and maintenance costs, and $102.2 million in taxes, which are outweighed by $178.7 million in additional fixed costs, $1.1 billion in capital costs, $116.5 million in transmission costs, and $1.4 billion in utility profits (see Figure D-7).

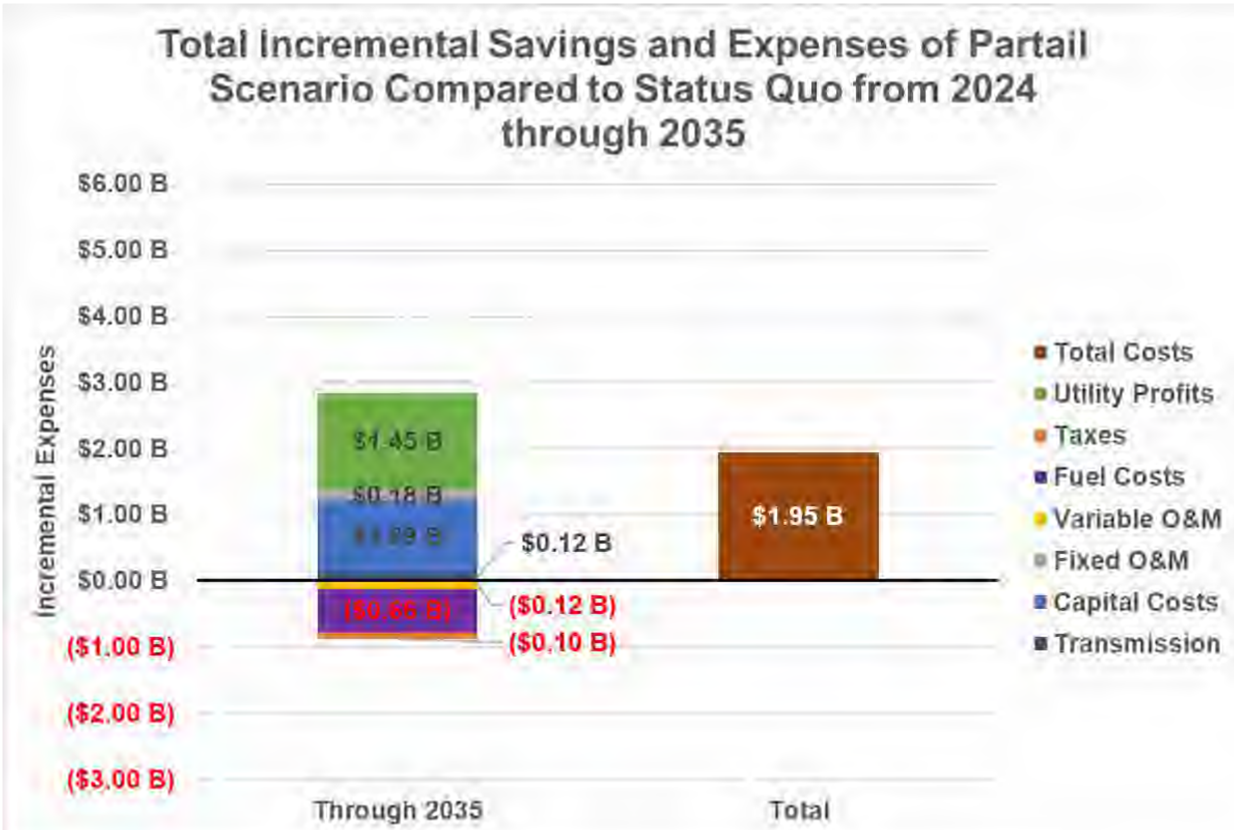

Figure D-7. The Partial scenario will cost MISO ratepayers an additional $1.9 billion from 2024 through 2035.

These incremental costs mean Load Serving Entities will incur an additional $1.9 billion because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $337 million of additional expenses compared to the Status Quo scenario (see Figure D-8).

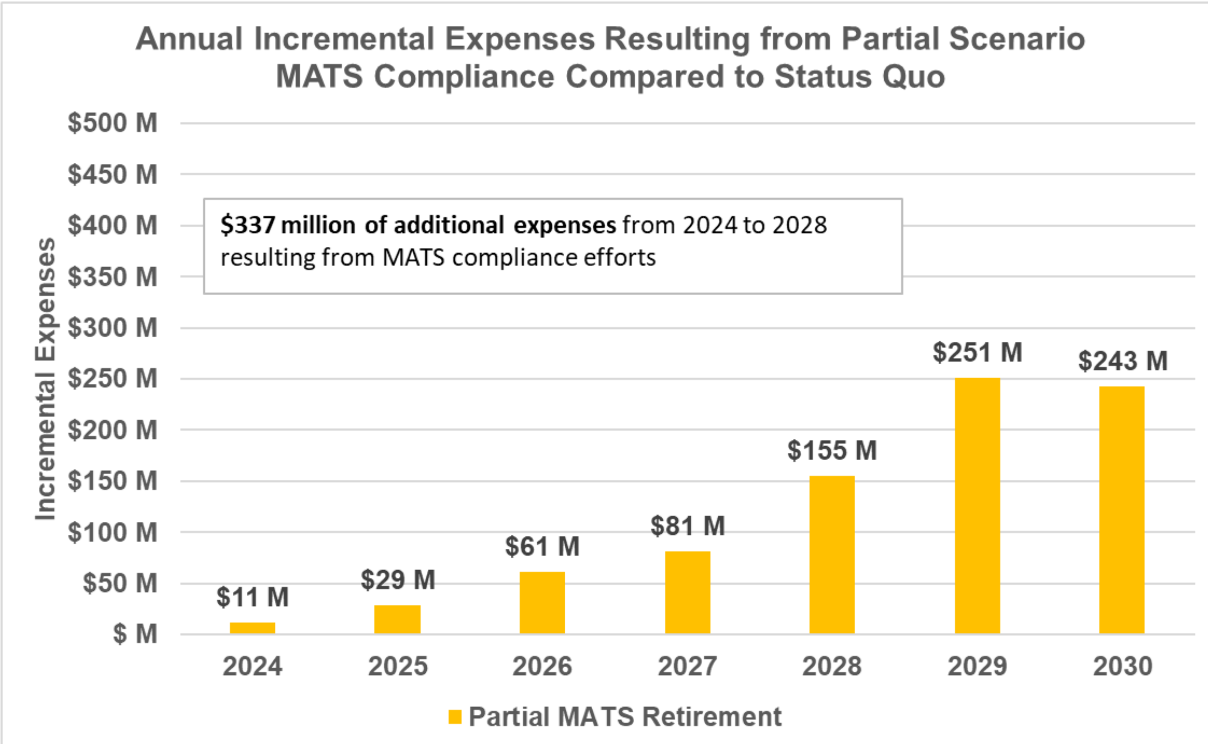

Figure D-8. This figure shows the annual incremental cost incurred by LSEs as a result of the lignite closures in the Partial scenario.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.95 cents per kWh in the Partial scenario, an increase of nearly 3.9 percent relative to current costs of 9.58.

Full MATS scenario:

Under the Full scenario, 2,264 MW of lignite capacity would be forced to retire resulting results in an incremental increase in replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage compared to the Status Quo scenario.

The total cost of replacement generation for the Full scenario is $16.8 billion, and the total incremental cost is $3.8 billion compared to Status Quo scenario. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Full scenario saves $33.3 billion in fuel costs, $11.7 billion in variable operations and maintenance costs, and $5.2 billion in taxes. However, these savings are far outweighed by $5.4 billion in additional fixed costs, $18.1 billion in capital costs, $2.4 billion in transmission costs, and $41.1 billion in utility profits (see Figure D-9).

Figure D-9. The Full scenario results in an increase of $16.76 billion in costs compared to the current grid.

Compared to the Status Quo scenario, the incremental savings are $1.3 million in fuel costs, $235.1 million in variable operations and maintenance costs, and $202 million in taxes, which are outweighed by $350.8 million in additional fixed costs, $2.1 billion in capital costs, $229.1 million in transmission costs, and $2.8 billion in utility profits (see Figure D-10).

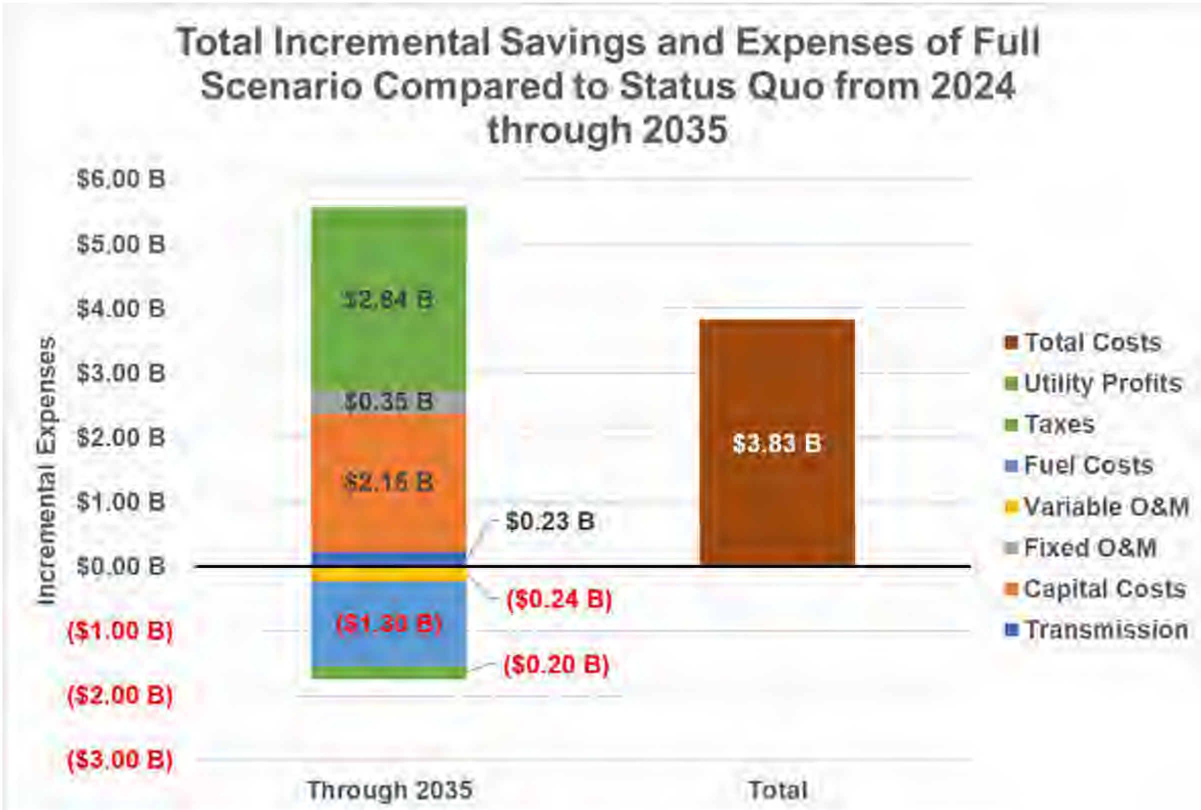

Figure D-10. This figure itemizes the expenses incurred in the Full scenario, which will cost an additional $3.8 billion compared to the Status Quo scenario.

These incremental costs mean Load Serving Entities will incur an additional $3.8 billion in the Full scenario because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $654 million of additional expenses compared to the Status Quo scenario (see Figure D-11).

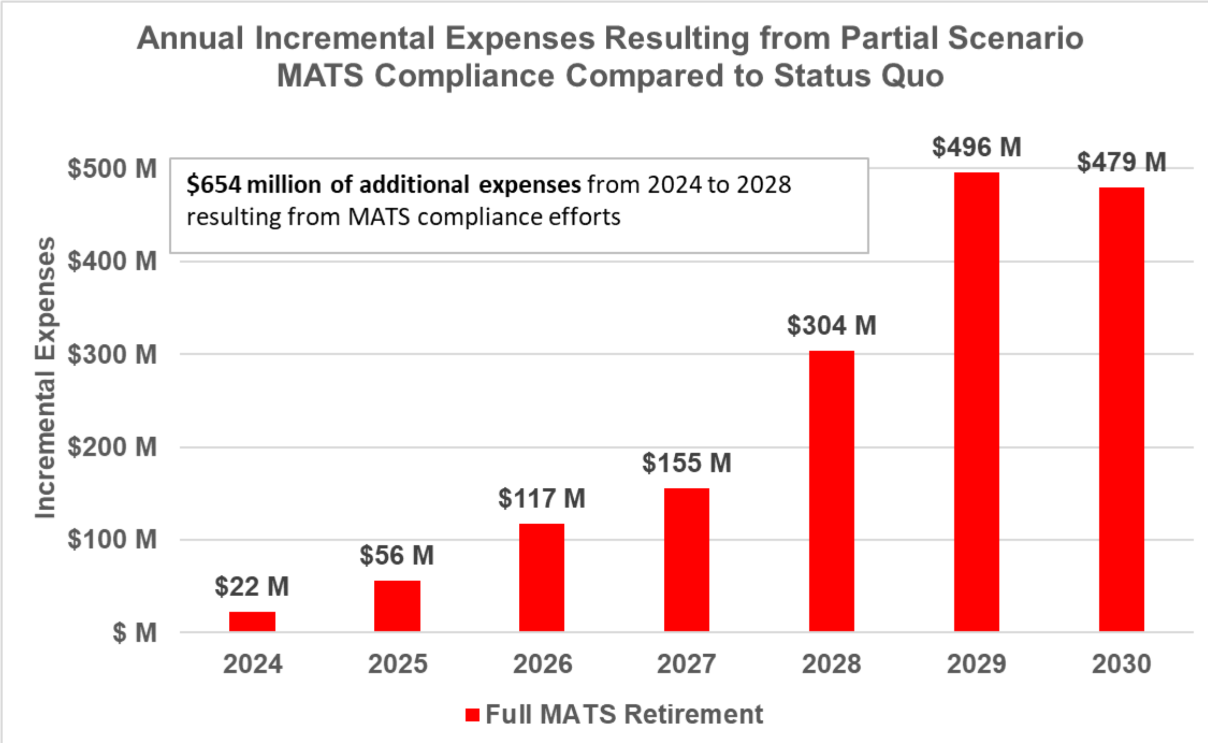

Figure D-11. LSEs would incur an additional $654 million in additional expenses, compared to the Status Quo scenario, as a result of the proposed MATS rules.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.97 cents per kWh in the Full scenario, an increase of nearly 4.1 percent relative to current costs of 9.58.

Conclusion:

By effectively eliminating the subcategory for lignite power plants and ignoring the breadth of evidence demonstrating that these regulations are not reasonably attainable, the MATS rules will increase the severity of capacity shortfalls in the MISO region, resulting in economic damages from the ensuing blackouts ranging from $29 million to $1.05 billion, depending on the HCY used, and imposing $1.9 billion to $3.8 billion in the cost of replacement generation capacity in the Partial and Full scenarios, respectively.

Therefore, the costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.[74]

[74] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.

Appendix 1: Modeling Assumptions

Electricity Consumption Assumptions

Annual electricity consumption in each model year is increased in accordance with EPA's assumptions in the IPM in each of the MISO subregions.

Peak Demand and Reserve Margin Assumptions

The modeled peak demand and reserve margin in each of the model years are increased in accordance with the IPM in each of the MISO subregions.

Time Horizon Studied

This analysis studies the impact of the proposed MATS rules from 2024 through 2035 to accurately account for the costs LSEs would incur by building replacement generation in response to the potential shutdown of lignite capacity.

This timeline downwardly biases the cost of compliance with the regulations because power plants are long term investments, often paid off over a 30-year time period. This means the changes to the resource portfolio in MISO resulting from these rules will affect electricity rates for decades beyond 2035.

Hourly Load, Capacity Factors, and Peak Demand Assumptions

Hourly load shapes and wind and solar generation were determined using data for the entire MISO region obtained from EIA's Hourly Grid Monitor. Load shapes were obtained for 2019, 2020, 2021, and 2022. [75] These inputs were entered into the model to assess hourly load shapes and assess possible capacity shortfalls in 2035 using each of the historical years.

Capacity factors used for wind and solar facilities were adjusted upward to match EPA assumptions that new wind and solar facilities will have capacity factors as high as 42.2 percent and 24.7 percent, respectively. These are generous assumptions because the current MISO-wide capacity factor of existing wind turbines is only 36 percent, and solar is 20 percent.

Our analysis upwardly adjusted observed capacity factors to EPA's estimates despite the fact that EPA's assumptions for onshore wind are significantly higher than observed capacity factors reported from Lawrence Berkeley National Labs, which demonstrates that new wind turbines entering operation since 2015 have never achieved annual capacity factors of 42.2 percent (See Figure D-12).[76]

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[75] Energy Information Administration, "Hourly Electric Grid Monitor," Accessed August 12, 2022, https://www.eia.gov/ electricity/gridmonitor/dashboard/electric_overview/balancing_authority/MISO

[76] Lawrence Berkely National Labs, "Wind Power Performance," Land Based Wind Report, Accessed July 27, 2023, https://emp.lbl.gov/wind-power-performance.

Figure D-12. This *figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 42.2 percent capacity factor on an annual basis.*

Another generous assumption is that we did not hold natural gas plants accountable to other EPA rules, such as the Carbon Rule, that may be in effect in addition to the MATS rule and would cap natural gas generators at 49 percent capacity factors to avoid using carbon capture and sequestration or co-firing with hydrogen. Doing so would have resulted in even more capacity shortfalls.

Line Losses

Line losses are assumed to be 5 percent of the electricity transmitted and distributed in the United States based on U.S. on EIA data from 2017 through 2021.[77]

Value of Lost Load

The value of lost load (VoLL) is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

[77] Energy Information Administration, "How Much Electricity is Lost in Electricity Transmission and Distribution in the United States," Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

Our analysis uses a conservative midpoint estimate of $14,250 per MWh for VoLL. This value is higher than MISO's previous VoLL estimate of $3,500 per MWh, but significantly lower than the Independent Market Monitor's suggested estimate of $25,000 per MWh.[78]

Plant Retirement Schedules

Our modeling utilizes announced coal and natural gas retirement dates from U.S. EIA databases and announced closures in utility IRPs using a dataset collected by NERA economic consulting.

Plant Construction by Type

The resource adequacy and reliability portions of this analysis use MISO Interconnection Queue data to project into the future. EPA capacity values are applied to each newly constructed resource until the MISO system hits its target reserve margin based on EPA's peak demand forecast in its IPM.

Load Modifying Resources, Demand Response, and Imports

Our model allows for the use of 7,875 MW of Load Modifying Resources (LMRs) and 3,638 MW external resources (imports) in determining how much reliable capacity will be needed within MISO to meet peak electricity demand under the new MATS rules.

Utility Returns

Most of the load serving entities in MISO are vertically integrated utilities operating under the Cost-of-Service model. The amount of profit a utility makes on capital assets is called the Rate of Return (RoR) on the Rate Base. For the purposes of our study, the assumed rate of return is 9.9 percent with debt/equity split of 48.92/51.08 based on the rate of return and debt/equity split of the ten-largest investor-owned utilities in MISO.

Transmission

This analysis assumes the building of transmission estimated at $10.3 billion, which is consistent with MISO tranche 1 for the Status Quo Scenario. For the Full and Partial scenarios, transmission costs are estimated to be $223,913 per MW of new installed capacity to account for the increased wind, solar, storage, and natural gas capacity additions.

Taxes and Subsidies

Additional tax payments for utilities were calculated to be of 1.3 percent of the rate base. The state income tax rate of 7.3 percent was estimated by averaging the states within the MISO region. The

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[78] Potomac Economics, "2022 State of the Market Report for the MISO Electricity Markets," Independent Market Monitor for the Midcontinent ISO, June 15, 2023, https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

Federal income tax rate is 21 percent. The value of the Production Tax Credit (PTC) is $27.50. The Investment Tax Credit (ITC) 30 percent through 2032, 26 percent in 2033, and 22 percent in 2034.

Battery Storage

Battery storage assumes a 5 percent efficiency loss on both ends (charging and discharging).

Maximum discharge rates for the MISO system model runs were held at the max capacity of the storage fleet, less efficiency losses. Battery storage is assumed to be 4-hour storage, while pumped storage is assumed to be 8-hour storage.

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[79] However, our study does not take wind or solar degradation into account.

Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs for all new generating units are sourced from the EIA 2023 Assumptions to the Annual Energy Outlook (AOE) Electricity Market Module (EMM). These costs are held constant throughout the model run. Expenses for fixed and variable O&M for new resources were also obtained from the EMM. MISO region capital costs were used, and national fixed and variable O&M costs were obtained from Table 3 in the EMM report.[80]

Discount Rate

A discount rate of 3.76 percent is used in accordance with EPA's assumptions in the IPM.

Unit Lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account. Wind turbines are assumed to last for 20 years, solar panels are assumed to last 25 years, battery storage for 15 years. Natural gas plants are assumed to last for 30 years.

Repowering

Our model assumes wind turbines, solar panels, and battery storage facilities are repowered after they reach the end of their useful lives. Our model also excludes economic repowering, a growing

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[79] Liam Stoker, "Built Solar Assets Are 'Chronically Underperforming,' and Modules Degrading Faster than Expected, Research Finds," PV Tech, June 8, 2021, https://www.pv-tech.org/built-solar-assets-are-chronically-underperforming-andmodules-degrading-faster-than-expected-research-finds/.

[80] U.S. Energy Information Administration, "Electricity Market Module," Assumptions to the Annual Energy Outlook 2022, March 2022, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

trend whereby wind turbines are repowered after just 10 to 12 years to recapture the wind Production Tax Credit (PTC). This trend will almost certainly grow in response to IRA subsidies.

EPA does not appear to take repowering into consideration because the amount of existing wind on its systems never changes. If our understanding of EPA's methodology is accurate, this a large oversight that must be corrected.

Fuel Cost Assumptions

Fuel costs for existing power facilities were estimated using FERC Form 1 filings and adjusted for current fuel prices.[81,82] Fuel prices for new natural gas power plants were estimated by averaging annual fuel costs within the MISO region according to EPA.[83] Existing coal fuel cost assumptions of $17.82 per MWh were based on 2020 FERC Form 1 filings.

Inflation Reduction Act (IRA) Subsidies

Our analysis assumes all wind projects will qualify for IRA subsidies and elect the Production Tax Credit, valued at $27.50 per MWh throughout the model run. Solar facilities are assumed to select the Investment Tax Credit in an amount of 30 percent of the capital cost of the project.

Appendix 2: Capacity Retirements and Additions in Each Scenario

This section details the capacity additions and retirements in the MISO region under each scenario.

Status Quo scenario: The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. Additions in the Status Quo scenario consist of 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.

Annual retirement and additions can be seen in Figure D-13 below.

[81] Trading Economics, "Natural Gas," https://tradingeconomics.com/commodity/natural-gas.
[82] https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region
[83] U.S. Energy Information Administration, "Open Data," https://www.eia.gov/opendata/v1/qb.php?category=40694&sdid=SEDS.NUEGD.WI.A

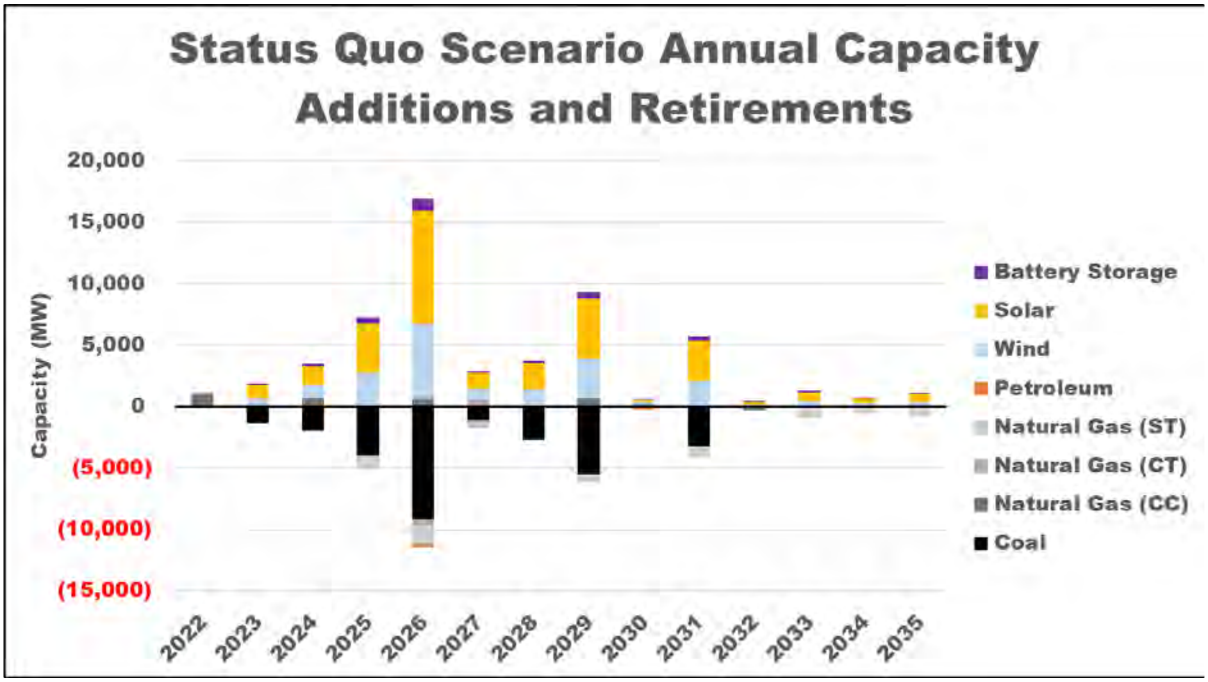


Figure D-13. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

Partial scenario: The Partial scenario results in the retirement of 29,908 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Partial scenario consist of 4,306 MW of natural gas, 20,451 MW of wind, 31,201 MW of solar, and 3,477 MW of storage (see Figure D-14). The incremental closure of 1,151 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage (see Figure D-15).[84]

[84] Replacement capacity is more than the retiring 1,151 MW of coal capacity because intermittent resources like wind and solar have lower capacity values than coal capacity.

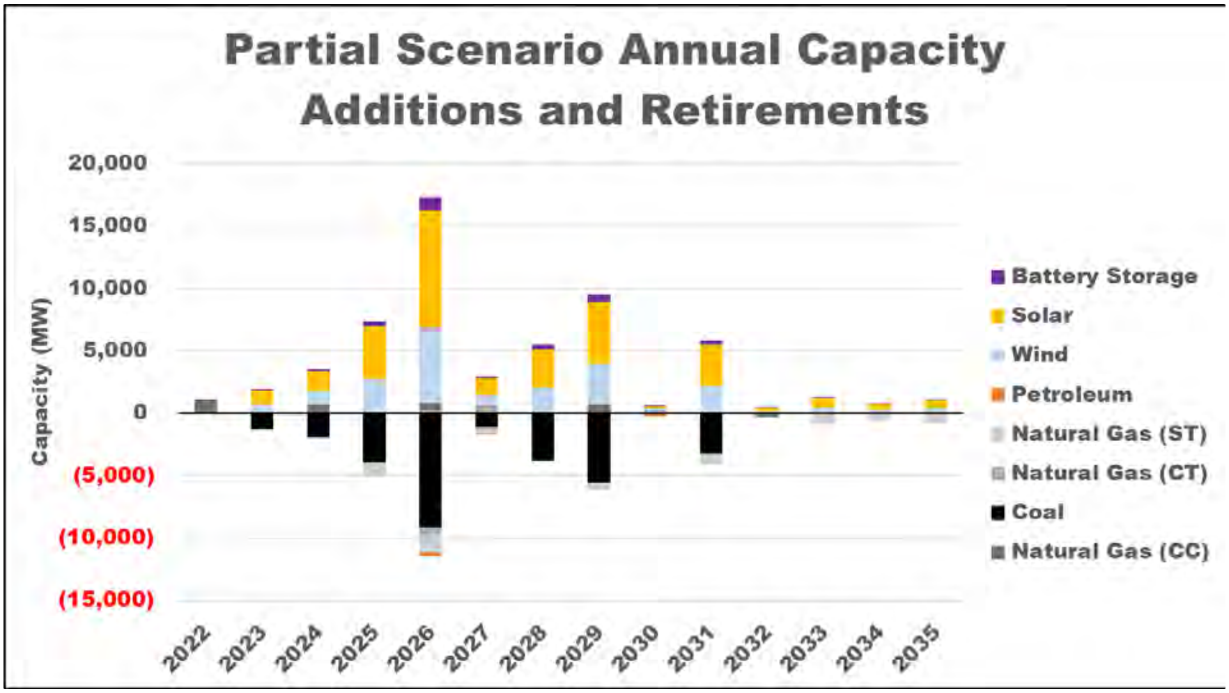


Figure D-14. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

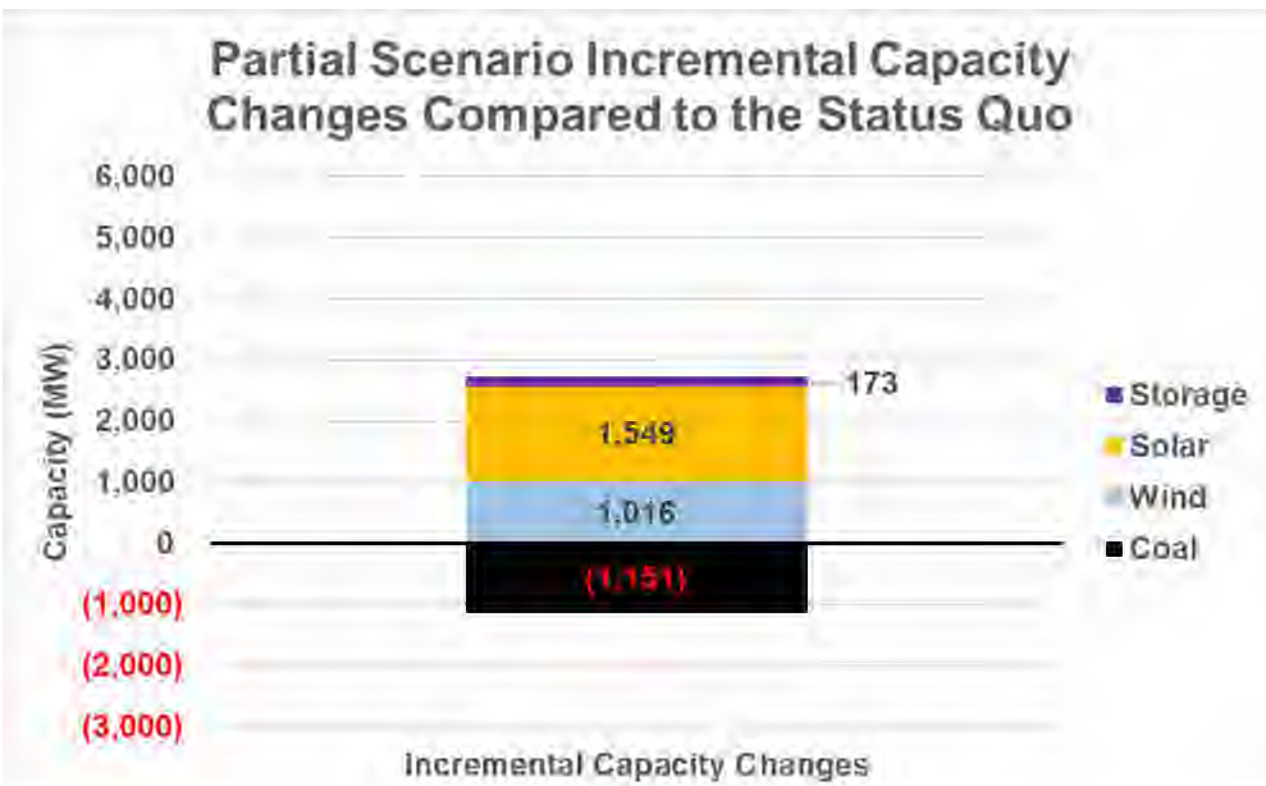


Figure D-15. This figure shows the incremental capacity retirements and additions in the MISO region under the Partial scenario.

Full Scenario: The Full scenario results in the retirement of 31,021 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Full scenario consist of 4,306 MW of natural gas, 21,433 MW of wind, 32,700 MW of solar, and 3,644 MW of storage (see Figure D-16). The incremental closure of 2,264 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage, compared to the Status Quo scenario (see Figure D-17).

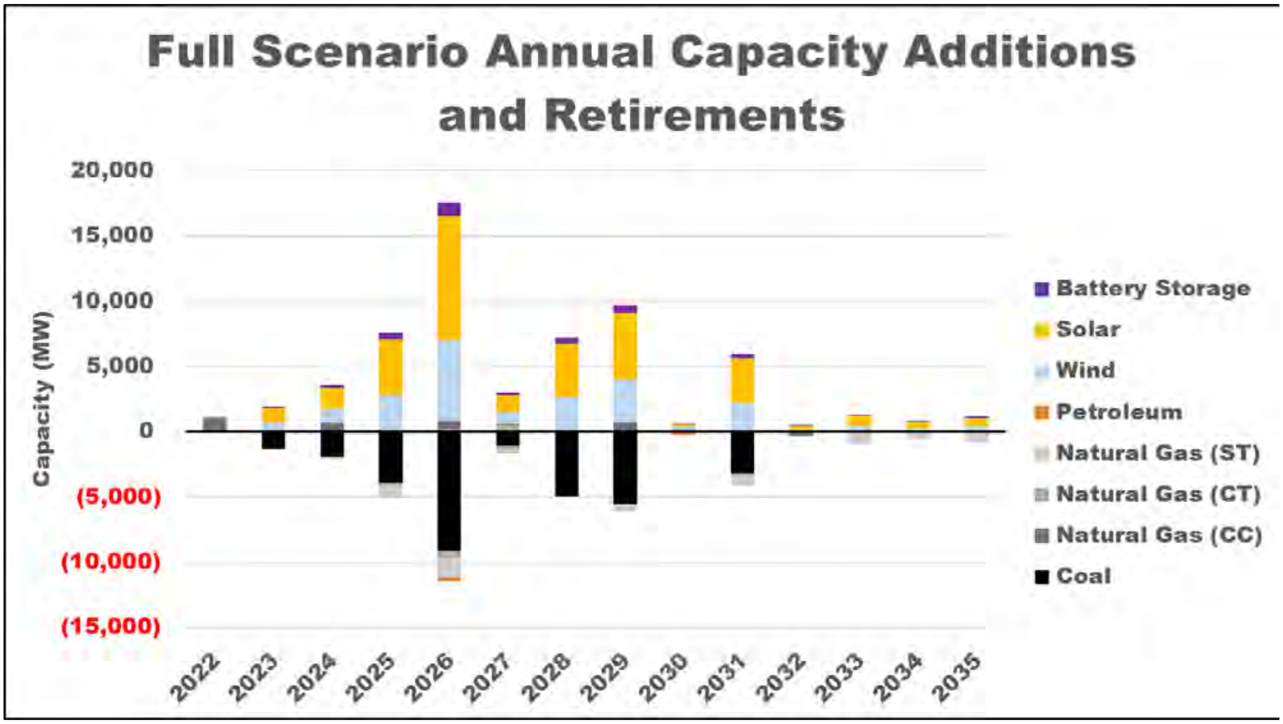


Figure D-16. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

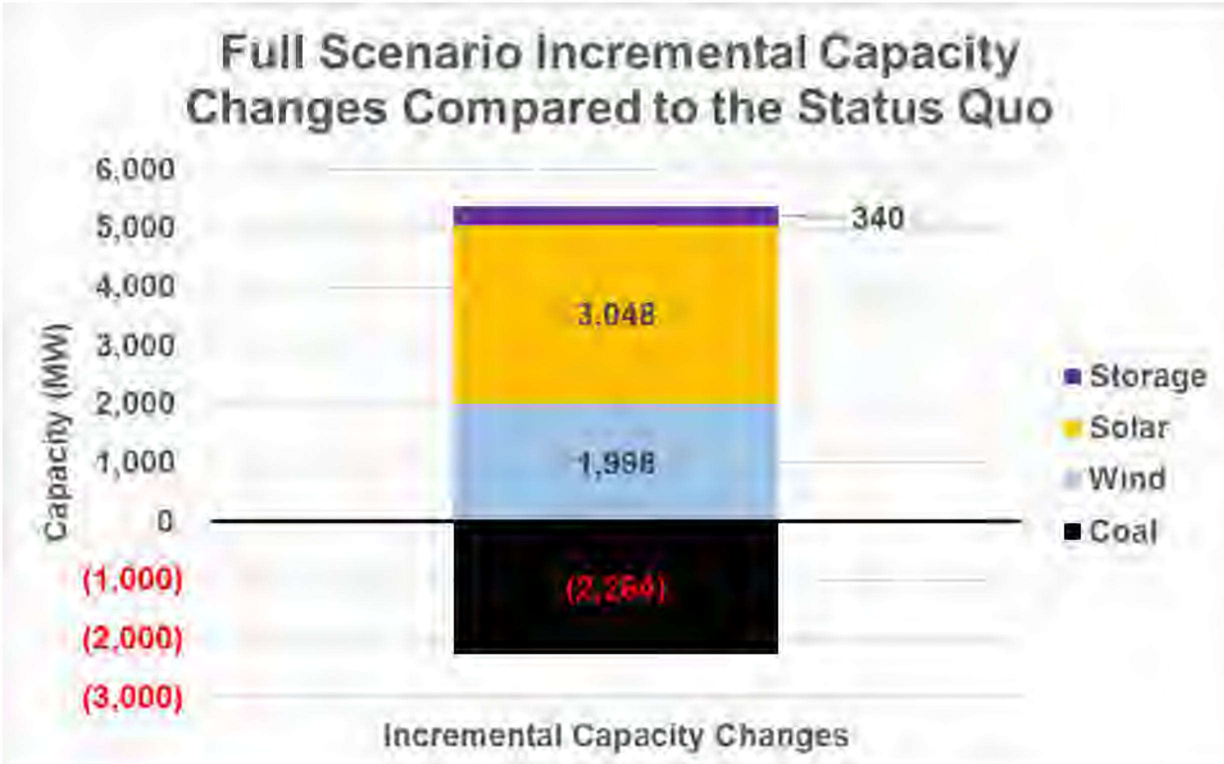


Figure D-17. This figure shows the incremental capacity closures and additions in the Full scenario.

Figure D-18 shows the capacity retirements and additions in the Partial and Full scenarios.

Comparison:

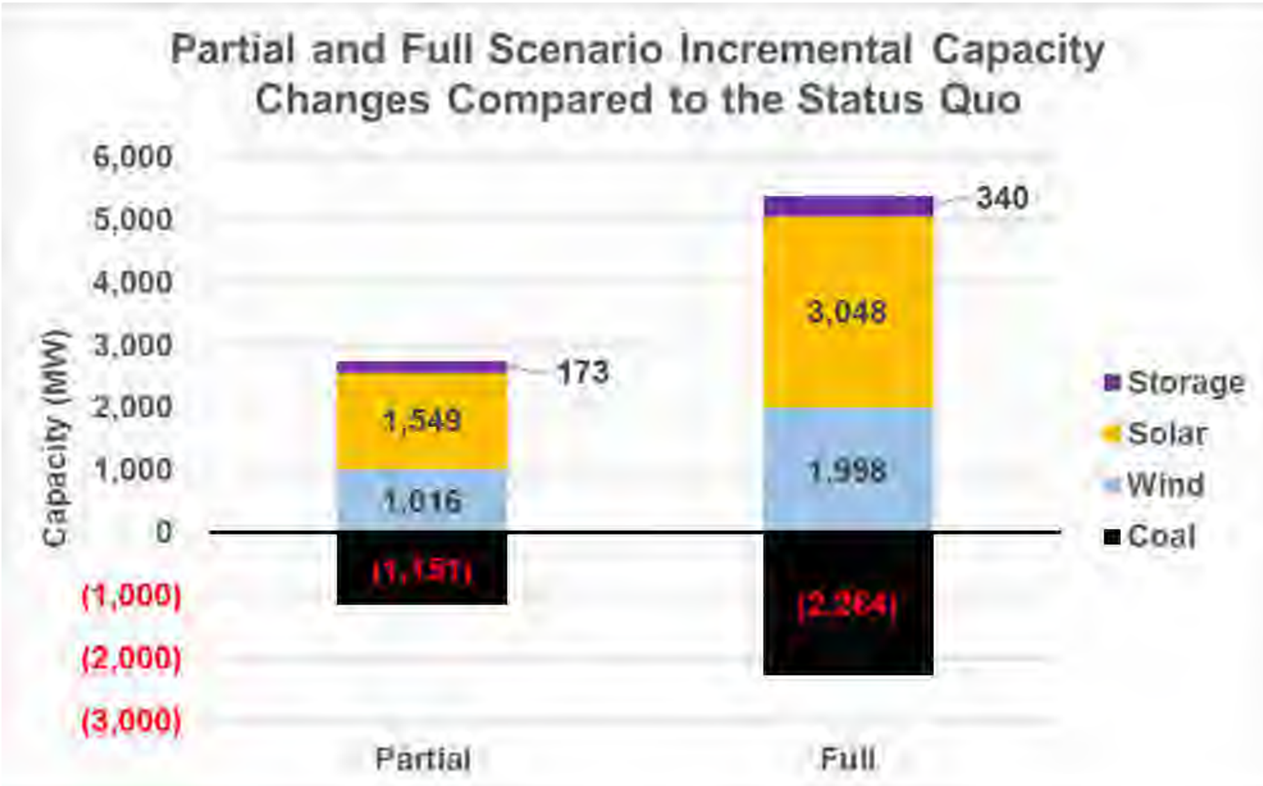


Figure D-18 comparison. This figure demonstrates the incremental retirements and additions in each scenario.

Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy

The capacity selected in our model to replace the retiring resources is based on two main factors. The first factor is the MISO interconnection queue, which is predominantly filled with solar and wind projects and a relatively small amount of natural gas. The second factor is the EPA's resource adequacy (RA) accreditation values in the Integrating Planning Model's (IPM) Proposed Rule Supply Resource Utilization file and Post-IRA Base Case found in the Regulatory Impact Analysis.

The IMP assumes a capacity accreditation of 100 percent for thermal resources, and variable intermittent technologies (primarily wind and solar) receive region-specific capacity credits to help meet target reserve margin constraints. Due to their variability, resources such as wind and solar received a lower capacity accreditation when solving for resource adequacy (see Table D-4).

EPA Integrated Planning Model

Capacity Accreditation in MISO

Resource	Capacity Value
Existing Wind	19%
Existing Solar	55%
New Onshore Wind 2035	17%
New Solar 2035	52%
Thermal	100%
Battery Storage	100%

Table D-4. This figure shows the capacity values for each resource based on EPA's estimates in its IPM.

In order to determine whether the available blend of power generation sources will be able to meet projected demand, each available generation source is multiplied against its capacity value, and the available resources are then "stacked" to determine if there is enough accredited power generation capacity to meet projected demand and maintain resource adequacy.

It should be noted that EPA's accreditation values from the IPM are generous compared to the accreditation values given by RTOs. For example, in the MISO region, grid planners assume that dispatchable thermal resources like coal, natural gas, and nuclear power plants will be able to produce electricity 90 percent of the time when the power is needed most, resulting in a UCAP rating of 90 percent. In contrast, MISO believes wind resources will only provide about 18.1 percent of their potential output during summer peak times, and solar facilities will produce 50 percent of their potential output. This report uses the generous capacity values provided by EPA; however, if the capacity values used by the RTOs were to be utilized, the projected energy shortfalls and blackouts would be even worse.

Appendix 4: Resource Adequacy in Each Scenario

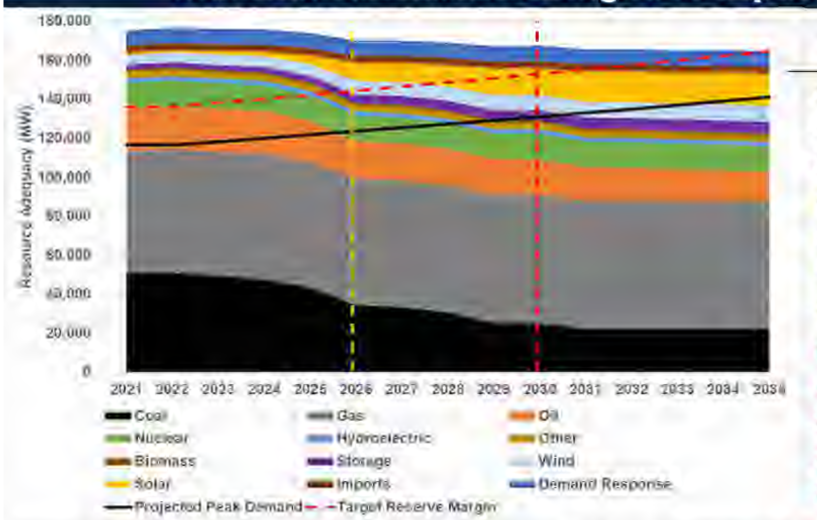
We performed a Resource Adequacy analysis on each of the three scenarios modeled to determine the potential impact to grid reliability in MISO region if implementation of the MATS Rule results in the forced retirement of lignite power plants.

Status Quo scenario

Under the Status Quo scenario, there is enough dispatchable capacity in MISO to meet the projected peak demand and target reserve margin established by EPA in the RIA documents

Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-19.[85]

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage, and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

Figure D-19. By 2030, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

Beginning in 2026, MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin, but the RTO still has enough dispatchable capacity to meet its projected peak demand. By 2030, the MISO region will rely on thermal resources and 4-hour battery storage to meet its peak demand, and by 2031 the region will no longer have enough dispatchable capacity or storage to meet its projected peak demand, and it will rely exclusively on non-dispatchable resources and imports to meet its target reserve margin.[86]

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-20 below. By 2035, dispatchable capacity consisting of thermal generation and battery storage will only be able to provide 91 percent of the projected peak demand, necessitating the use of wind and solar to maintain resource adequacy.

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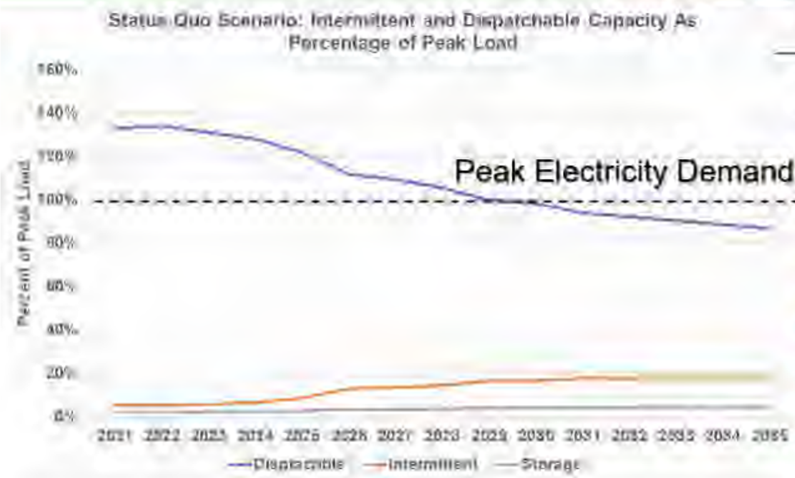
[85] Analysis of the Proposed MATS Risk and Technology Review (RTR) | US EPA, https://www.epa.gov/power-sector-modeling/analysis-proposed-mats-risk-and-technology-review-rtr

[86] While battery storage is considered dispatchable in this analysis for the sake of simplicity, battery resources are not a substitute for generation because as grids become more reliant upon wind and solar, battery resources may not be sufficiently charged to provide the needed dispatchable power.

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

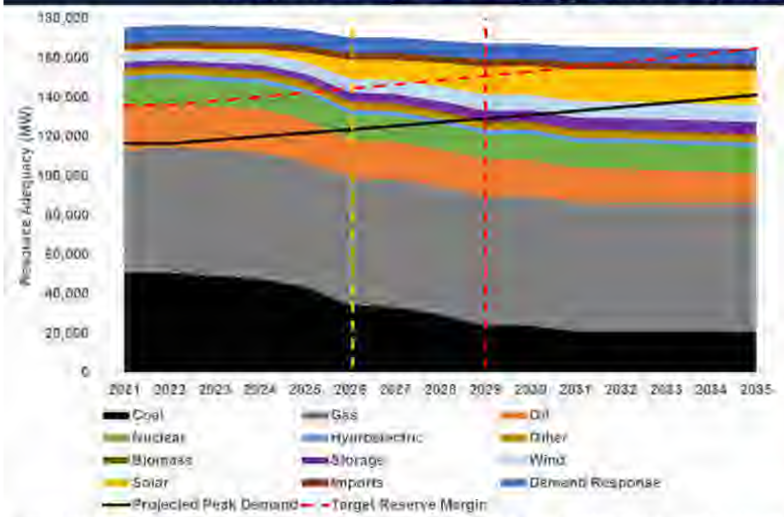
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

D-20. By 2035, dispatchable generators will only constitute 87 percent of projected peak demand, with storage accounting for four percent of peak demand capacity.

Partial scenario

Like the Status Quo Scenario, there is enough dispatchable capacity in MISO under the Partial scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-21.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	108%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-21. By 2029, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 105 percent in the Partial scenario, reflecting the loss of 1,151 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports, or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-22 below. By 2035, dispatchable capacity will only be able to provide 86 percent of the projected peak demand.

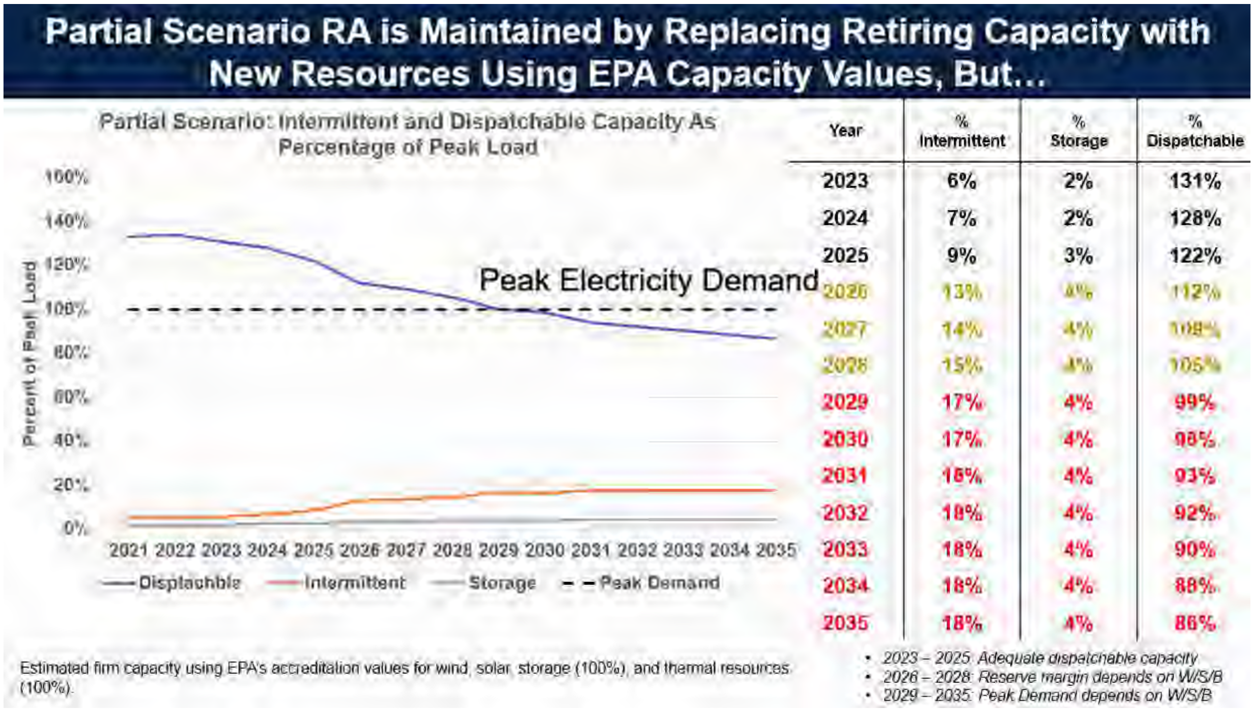
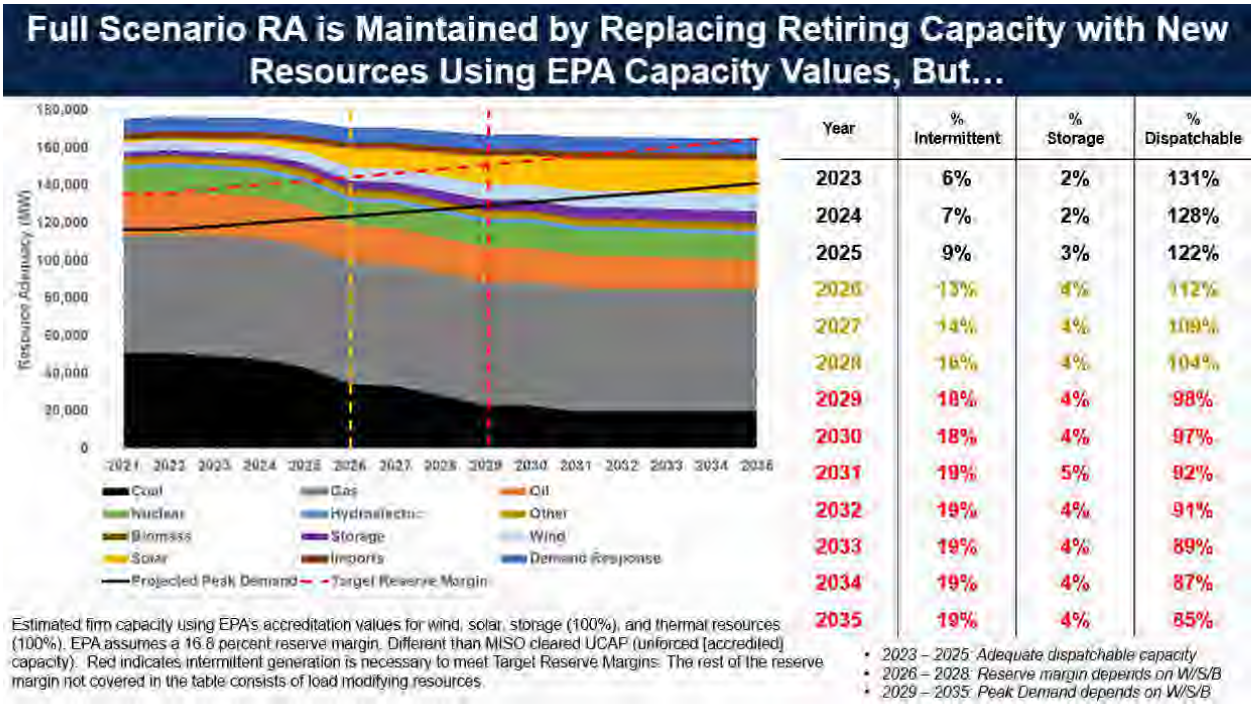


Figure D-22. The percentage of peak electricity demand being served by dispatchable resources drops by one percent in 2028, relative to the Status Quo scenario, due to the closure of lignite capacity in MISO due to the MATS rule.

Full scenario

Like the Status Quo scenario and Partial scenario, there is enough dispatchable capacity in MISO under the Full scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-23.



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

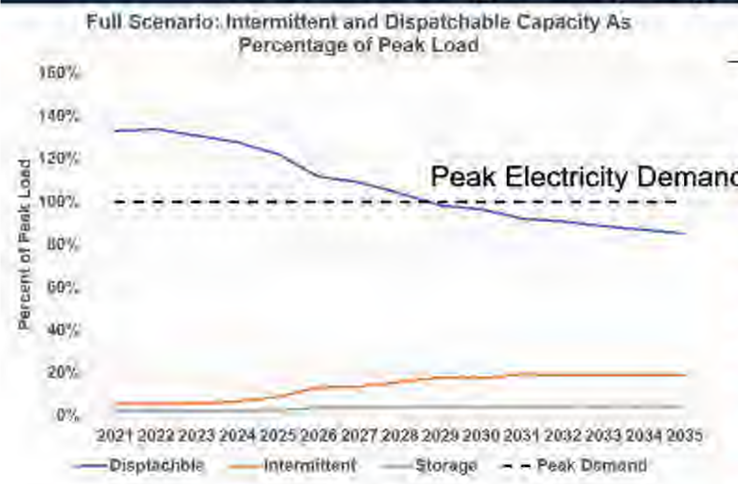
Figure D-23. The amount of dispatchable capacity available to meet projected peak demand in 2028 falls from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the closure of all the lignite capacity in MISO that year.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the loss of 2,264 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-24 below. By 2035, dispatchable capacity will only be able to provide 85 percent of the projected peak demand, a two percent decline relative to the Status Quo scenario, necessitating the use of wind and solar to maintain resource adequacy.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	6%	109%
2028	16%	6%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-24. The amount of peak demand that can be met with dispatchable resources in 2028 falls from 106 in the Status Quo scenario to 104 in the Full scenario.

Exhibit 4

JERRY PURVIS
DECLARATION OF HARM IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

1. My name is Jerry Purvis. I am Vice President of Environmental Affairs at East Kentucky Power Cooperative, Inc. (East Kentucky). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have 30 years of experience in electrical power generation. I have been employed at East Kentucky since 1994. I hold a bachelor's degree in Chemistry from Morehead State University and a bachelor's degree in Chemical Engineering from the University of Kentucky. I have a Master of Business Administration from Morehead State University. As Vice President, I am responsible for promoting proactive environmental policies, implementing comprehensive compliance strategies, and supporting East Kentucky's sustainability goals. I manage East Kentucky's staff and outside consultants in pursuit of these goals.

3. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's (EPA) National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review (the Final Rule or the MATS RTR).

4. East Kentucky is a not-for-profit electric generation and transmission cooperative headquartered in Winchester, Kentucky. East Kentucky is owned, operated, and governed by its members, who use the energy and services East Kentucky provides. These owner-member cooperatives provide energy to 520,000 homes, farms, and businesses across 87 counties in Kentucky. East Kentucky's purpose is to generate electricity and transmit it to 16 Owner-Member cooperatives that distribute it to retail, end-use consumers (Owner-Members). East Kentucky provides wholesale energy and services to Owner-Member distribution cooperatives through baseload units, peaking units, hydroelectric power, solar panels,

landfill gas to energy units and distributed generation resource power purchases – transmitting power across the rural Kentucky areas via more than 2,900 miles of transmission lines. East Kentucky's Owner-Members' collective customer base is comprised largely of residential customers (93%). And, in 2019, 57% of East Kentucky's owner-member retail sales were to the residential class. Electricity is the primary method for water heating and home heating for this class of customers.

5. East Kentucky is a member of PJM Interconnection (PJM). PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in 13 states and the District of Columbia.

6. East Kentucky is a member of the National Rural Electric Cooperative Association (NRECA). NRECA represents the interests of rural electric cooperatives across the country.

7. Demand for electricity is increasing in Kentucky. East Kentucky predicts increased demand during the time span in which this Final Rule would impact. East Kentucky forecasts net total energy requirements to increase from 13.5 to 16.7 million MWh (megawatt hours), an average of 1.5

percent per year over the 2021 through 2035 period.[1] Residential sales will increase by 0.7 percent per year, and small commercial sales (customers with ≤1000 KVA (kilo-volt-amperes)) will increase by 0.9 percent per year. The greatest area of growth will be for large commercial and industrial sales (customers with >1000 KVA), projected to increase by 3.3 percent per year.

8. East Kentucky is the voice for a substantial number of end users of electricity in its service territory that live in impoverished communities. These communities place a high value on affordable energy costs. East Kentucky's service territory includes rural areas with some of the lowest economic demographics in the United States. In these areas, families are literally faced with a daily choice between food, electricity, and medicine. Of the 87 counties that East Kentucky's Owner-Member cooperatives serve, 40 counties experience persistent poverty, as reported by the USDA.

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[1] East Kentucky Integrated Resource Plan, Load Forecast 2021-2035 (Dec. 2020) (IRP 2020).

9. Many of these hardworking Americans have been plagued by unemployment from mines, trucking companies, restaurants and other businesses. The unemployment rate is 60% higher than the national average. They rely on government assistance to survive; anywhere from 30% to 54% of total income in most of the counties that East Kentucky serves comes from governmental assistance programs. Forty-two percent of these electricity users are elderly (65 years or older). Many are on fixed incomes and reside in energy-leaking mobile homes. Recent brutal cold weather has caused their monthly electric bills to skyrocket. East Kentucky has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.

10. The MATS RTR threatens the viability of one of East Kentucky's essential coal-fired assets. It places burdens on the power sector, as a whole, and causes harm to our customers, including rural families, dependent on affordable, reliable electricity.

EAST KENTUCKY'S IMPACTED ELECTRIC GENERATING UNITS

11. East Kentucky owns electric generating units (affected EGUs) that fall within the Final Rule's scope of coverage and thus must comply with the Final Rule's stringent new filterable particulate matter (fPM) standard for coal-fired units. The Final Rule requires East Kentucky to expend substantial costs to comply with the fPM portion of the Rule that, ultimately, the rural ratepayers in East Kentucky's service area, must bear. Moreover, the Final Rule is so stringent that the margin between compliance and non-compliance is so thin that even a minor glitch would very likely cause a forced outage that would otherwise unnecessarily expose East Kentucky and its ratepayers to performance penalties in PJM and substantial exposure in the energy markets. Given the rapid growth in demand for electricity from large data centers and other new and expanding loads – coupled with the EPA's other chorus of new rules that target greenhouse gas emissions, coal combustion residuals, effluents,

ozone and particulates – the cumulative impact of the Final Rule will be to further jeopardize grid stability and reliability.

12. Spurlock Station, East Kentucky's flagship plant, is located near Maysville, Kentucky on the Ohio River. All four units at Spurlock have state-of-the-art NOx, SO_2, PM, and Hg controls. Spurlock Station combusts bituminous coal.

13. Spurlock Unit 3 is a coal-fired circulating fluidized bed boiler (CFB) unit (278 MW), which is designed to emit less NOx and SO_2 in the combustion process. Unit 3 has a SNCR to control NOx, a dry FGD to control SO_2/SO_3, and a filter fabric baghouse to control fPM. In essence, as fPM passes out of the Unit 3 boiler, it passes through a structure filled with 8,256 fabric bags that collect the fPM for later disposal. The limits for this type of emission are measured in hundredths of a pound of material per million British Thermal Units of energy produced (lb./mmBtu). Unit 3 is adversely affected by the Final Rule.

14. Spurlock Unit 3 has a stellar MATS compliance record with no historical exceedances of MATS Rule requirements. The Final Rule

confirms that the existing fPM and other MATS limits, are sufficiently protective of human health and the environment. Therefore, East Kentucky's existing fPM controls provide ample protection to ensure the communities surrounding Spurlock Station enjoy clean air.

15. East Kentucky has made substantial investments in Spurlock Station due to recent EPA environmental rules, including a conversion to dry bottom ash, ash pond clean closure by removal, and a new waste water treatment system with evaporation to ensure the plant is fully compliant with Effluent Limitation Guidelines (ELGs) and the 2015 Coal Combustion Residuals (CCR) rule. Altogether, EKPC has invested $1.8 billion in environmental control equipment.

16. EKPC is presently evaluating the need for further extraordinary expenditures due to the EPA Rules released on April 25, 2024.[2] Collectively,

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[2] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024) (Greenhouse Gas Power Sector Rule); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR

these rules impose egregious financial impacts on EKPC, its members, and end users. This Final Rule's costs must be considered as cumulative environmental costs that will detrimentally impact the cost to heat and cool the homes of rural ratepayers in disadvantaged communities and to power the job-creating businesses that provide employment to these individuals.

MATS RTR RULE REVISIONS

17. The MATS RTR decreases the limit for fPM from 0.030 lb/mmBtu to 0.010 lb/mmBtu (the New fPM Limitation) – an unprecedented 67% reduction that imposes substantial risks to unit performance in PJM with little to no environmental benefit. The Final Rule

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Surface Impoundments, 89 Fed. Reg. 38950 (May 8, 2024); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024).

exceeds the point where the law of diminishing returns suggests that the additional limitations are not warranted.

18. The Final Rule also requires adoption of continuous emission monitoring systems (CEMS) as the only method to demonstrate compliance with the New fPM Limitation, eliminating the option to use quarterly stack testing and also eliminating the Low Emitting EGU (LEE) program. These requirements will increase the costs associated with program compliance without offering any substantial benefit beyond what the current measurement and verification procedures already afford.

19. Compliance with the New fPM Limitation and installation of PM CEMS are required on or before three years after the effective date of the Final Rule. To be able to meet these deadlines, East Kentucky and other utilities must begin work now to be in a position to comply.

20. The MATS RTR also eliminates the low rank coal subcategory for lignite-powered facilities and revises the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the New Mercury

Limitation). The New Mercury Limitation does not affect East Kentucky because the cooperative's coal-fired plants do not combust lignite fuels.

THE NEW fPM LIMITATION WILL CAUSE IMMEDIATE AND IRREPARABLE HARM TO EAST KENTUCKY

21. Spurlock Unit 3 is not presently capable of meeting the New fPM Limitation of 0.010 lb/mmBtu on a sustained basis. Although no data exists to confirm that compliance can in fact be achieved, East Kentucky has devised an initial strategy to improve fPM removal performance of the Spurlock Unit 3 baghouse.

22. To attempt to meet the New fPM Limitation, Spurlock Unit 3 must expeditiously begin a study and upgrades to its baghouse (the Baghouse Upgrade Project). The cost of the Baghouse Upgrade Project causes additional financial harm to East Kentucky and its owner-members.

23. Given the requirements associated with designing, permitting, financing and securing state regulatory approval for the Baghouse Upgrade Project, work must begin during the early pendency of this litigation due to the compliance date for the Final Rule.

24. It is unknown to what extent the Baghouse Upgrade Project will improve Unit 3's fPM emission rates. Regardless of the potential improvements of the Project, the 2005-vintage baghouse installed at Unit 3 was not designed to meet 0.010 lb/mmBtu. The baghouse is undersized to achieve the fPM Limitation and must operate flawlessly to attain compliance. In East Kentucky's experience with baghouse operation at CFB units, the Unit 3 baghouse will certainly fail, despite best engineering and maintenance practices, due to the lack of any margin to meet the aggressively low new fPM Limitation.

25. Therefore, East Kentucky anticipates being harmed by increased Unit 3 forced outages, resulting in potential penalties and exposure to market volatility in the PJM market. Lower fPM emission limitations, in general, put environmental control equipment under more stress in the summer and winter on peak days. Since the limit for fPM was reduced immensely (67%), there is little margin for error. **To put the effect of the Final Rule in context, a single hole the size of a human pinky finger in one of over 8,000 fabric filter bags within the baghouse can**

cause an exceedance of the new standard and, thereby, force the unit offline. It is simply unreasonable to think that a baghouse will perform perfectly under every operating condition in every period of the year. Even if Unit 3 and its upgraded baghouse achieve initial compliance with the Final Rule, the new and stricter fPM limitations on peak demand days – when PJM is calling for all available generators to produce power in order to avoid blackouts - stress the fPM controls to the point of a forced outage. Forced outages in PJM are unforgiving and highly penalized with the added injury of having to pay market prices for power during periods when it is least available and, therefore, most expensive. East Kentucky estimated, as an example, the penalty and damages caused by one forced outage event on Spurlock Unit 3 could easily exceed $31 million per seven-day outage. For a non-profit cooperative such as EKPC, an entire year's worth of margins could be wiped out in a single weekend of extreme weather.

Cost of Spurlock Unit 3 Seven Day Outage

PJM Market Pricing Conditions	Cost of Replacement Power for Unit 3	Lost Capacity Payment	PJM PAI Non-Performance Penalty	Total
Winter Average Cost	$1,640,785	$232,066	0	$1,872,851
Summer Average Cost	$1,600,361	$232,066	0	$1,832,427
Winter High Cost	$3,371,164	$232,066	0	$3,503,230
Winter Storm Event	$13,203,225	$232,066	$17,595,000	$31,030,291

Note 1: Winter Average Cost is based on replacement power at an average day-ahead price for January 2023
Note 2: Winter High Cost is based on replacement power at an average 168 highest hours of real-time LMP in January 2024
Note 3: Winter Storm Event is based on replacement power at an average 168 highest hours of real-time LMP in December 2022 around and including Winter Storm Elliott
Note 4: All prices include 7-days of power
Note 5: PJM Performance Assessment Interval (PAI) Non-Performance Penalty is assessed during a reliability event due to certain triggering events identified in the PJM Tariff, such as during a manual load shed event. The cost calculation assumes a 23 Hour PAI event.

26. The table above illustrates that, for an unplanned forced outage in PJM, EKPC could experience up to a $31,030,291 dollar penalty for not showing up as a result from a hole in the baghouse the size of a pinky finger. This illustrates the dissonance between the very marginal environmental impact of the Final Rule and the very real, tangible and irreparable harm that would result from a forced outage coming at an inopportune moment.

27. Of course, the foregoing analysis assumes that replacement power is even available for purchase from the PJM market during a Final

Rule-induced forced outage. PJM has signaled that EPA's new environmental regulations – particularly the Greenhouse Gas Power Sector Rule – will reduce the dispatchable capacity in the PJM system. PJM states, "[I]n the very years when we are projecting significant increases in the demand for electricity, the [Greenhouse Gas Power Sector] Rule may work to drive premature retirement of coal units that provide essential reliability services . . ." Plainly, any unit downtime exacerbates an already precarious reliability situation, especially considering the increasing demand for electricity in Kentucky and elsewhere in the PJM region.

28. East Kentucky, as a non-profit electric cooperative, has limited financial resources to risk PJM penalties of this magnitude, especially when layered with other environmental compliance projects due to EPA's recent rulemaking agenda. All of these projects must take place during the same time period. These costs will place upward pressure on rates for rural customers and impact East Kentucky's ability to supply affordable, reliable energy to customers.

THE MATS RTR CREATES GRID RELIABILITY CONCERNS

29. Compliance costs and increased maintenance needs associated with the Final Rule create a significant risk of energy reliability and economic hardship.

30. Spurlock Unit 3 would not be available during forced outage time periods because the baghouse is not designed to provide sufficient margin for compliance with the New fPM Limitation, such that even a pinky-sized hole in one of the baghouse bags would cause an exceedance. During these time periods, existing generation resources may not be adequate in Kentucky to sustain the grid. Multiple new EPA environmental regulations directly and profoundly impact generation resources in Kentucky, causing multiple unit retirements in a short time frame. This Final Rule makes it more likely that Spurlock Unit 3 will be forced off-line when PJM depends upon it the most, contributing to cumulative reliability concerns.

31. If the interruption of power delivery from a grid failure occurs, East Kentucky, its members, the economy, and the public health of end

users in its service territory would be immediately harmed. Kentuckians rely on electricity to heat and cool their homes. Affordable and consistent power supports essential health services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from the grid failure during winter storm Elliott in the PJM area shows the documented health impacts and morbidity caused by those events. Other concrete damages would occur such as business shutdowns, food spoilage, property damage, and lost labor productivity.

32. Further economic development in Kentucky is at risk without the ability to provide sufficient energy to support new factories, data centers, and other infrastructure necessary to attract industry, and, in turn, create new jobs. Energy powers the economy from which the government derives tax revenues. The MATS RTR imposes tremendous new risks on East Kentucky and the power grid while offering benefits that are, at best, marginal.

SUMMARY OF HARM TO EAST KENTUCKY

33. At this time, Spurlock Unit 3 cannot currently meet the New fPM Limitation on a sustained basis.

34. East Kentucky must immediately expend several million dollars to determine how Spurlock Unit 3's fPM performance can be improved. Irrespective of the Project improvements, the Unit 3 baghouse's design provides virtually no compliance margin. However, the reality of the current state-of-the-art dictates that there will be failures from time to time. A very small hole in a single bag is the margin of error between compliance and enormous risk of exposure to PJM performance penalties and energy market exposures.

35. East Kentucky is harmed by the MATS RTR because it must expend financial resources to commence the Baghouse Upgrade Project sooner than later to lower its fPM emissions and to meet the MATS RTR compliance deadline. The Final Rule's unyielding mandates will result in less reliability and greater costs with no significant improvement in air quality.

36. These costs cannot be deferred or delayed until the courts reach a final determination on the merits of the Petition for Review and all appeals are exhausted. East Kentucky expects that could take several years. If the Final Rule remains in effect while challenges are pending, East Kentucky will have no choice but to incur significant non-refundable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above. The consumers who rely on power generated by East Kentucky might find themselves with less reliable power or without the means to pay for it or both.

* * * *

[Signature Follows on Next Page]

I declare under penalty of perjury that the foregoing is true and correct.

Jerry Purvis

Jerry Purvis

Dated: 6/5/2024

Exhibit 5

GAVIN A. MCCOLLAM
DECLARATION OF HARM IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

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

2. I have more than 35 years of experience in electricity generation. I have been employed at Basin Electric since 1989. I hold an associate's degree from Bismarck (North Dakota) State College, a bachelor's degree in mechanical engineering from North Dakota State University, and a master's degree in systems management from the University of Southern California. I am also a registered professional engineer. As the Senior Vice President and Chief Operating Officer at Basin Electric, my responsibilities include ensuring access to safe, reliable, affordable and sustainable electricity for Basin Electric's member-owner cooperatives. This includes oversight of Basin Electric's coal-fired electric generating units in North Dakota and Wyoming.

3. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's ("EPA") National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review ("Final Rule" or "MATS RTR").

4. Basin Electric is a not-for-profit generation and transmission cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives. Those member cooperatives—140 of them—are Basin Electric's owners. Through them, Basin Electric serves approximately three million consumer members in an area that covers roughly 500,000 square miles across nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Basin Electric's end-use consumer members across these nine states include residential, farm, commercial, industrial, and irrigation electric consumers. As of the end of 2023, Basin Electric had an asset base of $8 billion and operated 5,219 megawatts ("MW") of wholesale electric generating capability and had 8,112 MW of generating

capacity within its portfolio. Those owned electric generation facilities are located in the states of Iowa, Montana, North Dakota, South Dakota, and Wyoming. Three of Basin's electric generation facilities are expected to be significantly impacted by the MATS RTR: Antelope Valley Station, Leland Olds Station, and Laramie River Station.

5. Basin Electric is one of the few utilities that supplies electricity on both sides of the national electric system separation. In the Eastern Interconnection, Basin Electric's system is part of two assessment areas overseen by two System Operators: the Southwest Power Pool ("SPP") and the Midcontinent Independent System Operator ("MISO"). In the Western Interconnection, Basin Electric's system is overseen by the Northwest Power Pool ("NWPP") and the Rocky Mountain Reserve Group ("RMRG"). These System Operators regulate the multiple energy and capacity markets that exist within each regional grid. They also require utilities like Basin Electric to maintain a certain amount of capacity to ensure reliability during periods of high demand.

6. Basin Electric, which has two North Dakota facilities that are fueled by lignite coal, is a member of the Lignite Energy Council ("LEC"). LEC represents the regional lignite industry in North Dakota, an $18

billion industry critical to the economy of the Upper Midwest and the reliability of its electrical grid. The primary objective of LEC is to maintain a viable lignite coal industry and enhance development of the region's lignite resources. Members of LEC include mining companies, utilities that use lignite to generate electricity, synthetic natural gas, and other valuable byproducts, and businesses that provide goods and services to the lignite industry. LEC has advocated for its members since 1974 to protect, maintain, and enhance development of our region's abundant lignite resources. LEC is committed to environmental stewardship and understands the importance of protecting North Dakota's natural beauty.

7. Basin Electric is also member of the National Rural Electric Cooperative Association ("NRECA"). NRECA represents the interests of rural electric cooperatives across the country.

8. Lignite is frequently utilized at mine-mouth power generation facilities, which are coal-fired power plants built near a coal mine that use coal from that mine as fuel.

9. The MATS RTR threatens the viability of lignite-powered plants. It also threatens the reliability of the entire grid across the region,

places burdens on the power sector as a whole, and causes harm to industries dependent on a reliable electric grid.

ANTELOPE VALLEY STATION

10. Basin Electric is the operator and part owner of the Antelope Valley Station ("Antelope Valley"), a two-unit power plant located in Mercer County, North Dakota. Each EGU is rated at 450 MW. Antelope Valley began commercial operation in 1984. Antelope Valley Station is fueled by lignite coal from the nearby Freedom Mine.

11. At Antelope Valley, sulfur dioxide ("SO2") emissions from the Combustion Engineering tangentially fired boiler are controlled by a dry scrubber. Nitrogen oxide ("NOx") emissions were originally controlled by low NOx burners and close-coupled-over-fired air. Then, in spring 2016, an additional separated over fired air system was installed and reduced NOx emissions lower. Other pollution control equipment installed at Antelope Valley includes a fabric-filter system for particulate control and sorbent injection for mercury control.

LELAND OLDS STATION

12. Basin Electric is the operator and owner of the Leland Olds Station ("Leland Olds"), a two-unit power plant located in Mercer County,

North Dakota. The two units together generate 660 MW. Unit 1 began commercial operation in 1966 and Unit 2 began commercial operation in 1975. Leland Olds is fueled by lignite coal delivered by rail from the Freedom Mine.

13. At Leland Olds Unit 1, SO2 emissions from the Babcock & Wilcox wall-fired boiler are controlled by a wet scrubber. NOx emissions were originally controlled by low NOx burners. Then, in spring 2017, a selective non-catalytic reduction ("SNCR") system was installed and reduced NOx emissions lower. Other pollution control equipment installed at Unit 1 includes an electrostatic precipitator ("ESP") system for particulate control and activated carbon (sorbent) injection for mercury control.

14. At Leland Olds Unit 2, NOx emissions from the boiler are controlled by low-NOx burners, separated over-fired air, and SNCR. A wet scrubber is used to control SO2 emissions and an ESP is used for control of particulate matter ("PM") emissions. An activated carbon injection system is used to control mercury emissions.

LARAMIE RIVER STATION

15. Basin Electric is the operator and a minority co-owner of the Laramie River Station ("Laramie River"), a three-unit power plant located in Wheatland, Wyoming. The three units together generate approximately 1,700 MW, of which Basin Electric owns about 42%, for a total of roughly 714 MW. Unit 1 began commercial operation in 1980, Unit 2 began commercial operation in 1981, and Unit 3 began commercial operation in 1982. Laramie River is fueled by subbituminous coal from the Powder River Basin in Wyoming.

16. At Laramie River Unit 1, the NOx emissions from the boiler are controlled by low-NOx burners and separated over-fired air. A wet scrubber is used to control SO2 emissions and an ESP is used for control of PM emissions. An activated carbon injection system is used to control mercury emissions.

17. At Laramie River Unit 2, the NOx emissions from the boiler are controlled by low-NOx burners and separated over-fired air. In 2019, Unit 2 began operation of a SNCR. A wet scrubber is used to control SO2 emissions and an ESP is used for control of PM emissions. An activated carbon injection system is used to control mercury emissions.

18. At Laramie River Unit 3, the NOx emissions from the boiler are controlled by low-NOx burners and separated over-fired air. A dry scrubber is used to control SO2 emissions and an ESP is used for control of PM emissions. An activated carbon injection system is used to control mercury emissions.

MATS RTR RULE REVISIONS

19. The MATS RTR eliminates the low rank coal subcategory for lignite-powered facilities and changes the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the "New Mercury Limitation").

20. The MATS RTR decreases the limit for filterable particulate matter ("fPM") to 0.010 lbs/MMBtu (the "New fPM Limitation").

21. Compliance with the New Mercury and New fPM Limitations is required on or before three years after the Final Rule's effective date.

22. The MATS RTR provides that Continuous Emission Monitoring Systems ("CEMS") are the only method to demonstrate compliance with the fPM limit.

LIGNITE COMBUSTION

23. It is well-known and consistent with Basin Electric's experience that lignite deposits vary significantly in quality, including fuel combustion performance and mineral content. Mercury content in the lignite varies because different seams within the mine yield lignite with diverse attributes (including mercury) on a day-to-day basis. A compliance margin is critical to allow for continuous compliance with the Final Rule especially considering coal quality variability.

24. Lignite varies in composition and the distribution of mercury within individual coal samples is not uniform, unlike other types of coals. The amount of mercury within one seam of coal can vary drastically, not to mention mercury content fluctuations between seams at the same mine.

25. An important difference between mine-mouth coal plants and typical coal-fired power plants is the control over fuel composition. Non-mine-mouth facilities purchase coal of a specified quality to be delivered to the facility. Unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, many North Dakota lignite units are located at mine-mouth facilities without

access to other coal types. Antelope Valley cannot use bituminous coal or other types of coal because the boilers were designed specifically for burning high moisture coal such as lignite. If Antelope Valley were to burn coal with lower moisture content, it would cause severe maintenance issues with heat transfer to the rear pendants and could result in a loss of produced electricity. Because Antelope Valley is a mine-mouth facility, having to rail in coal would significantly change the fuel cost and therefore significantly increase the cost that Basin Electric bids Antelope Valley into the market.

26. Leland Olds uses lignite coal from the nearby Freedom Mine, which is loaded at Antelope Valley and delivered via rail. If Leland Olds were to change coal types, it would need to be transported much further and would not be cost effective.

27. When high mercury batches of coal are combusted, the original MATS mercury emission limitation from 2012 provided lignite power plants enough leeway to account for higher mercury emissions due to the mercury content in the coal.

ELIMINATION OF THE MERCURY SUBCATEGORY FOR LIGNITE CAUSES IMMEDIATE AND IRREPARABLE HARM TO THE NORTH DAKOTA LIGNITE INDUSTRY AND TO BASIN ELECTRIC

28. EPA established the lignite subcategory for mercury because lignite units and lignite coal are markedly different than bituminous and subbituminous coals. Lignite has a higher mercury content in many instances and presents greater variability than other coals. The higher sulfur content found in lignite fuels inhibits the ability of injected sorbents to reduce mercury emissions at lignite plants. The mercury content also results in higher levels of SO_3 formed, which significantly limits the mercury emission reduction potential of emission controls at lignite plants.

29. Basin Electric has used the same technology (combination of sorbent injection plus a chemical additive (oxidizing agent)) as its primary mercury control strategy since the MATS rule came into effect and is not aware of more effective control technology.

30. There is no evidence that the units at Antelope Valley and Leland Olds could achieve compliance with the New Mercury Limitation on a sustained basis with the currently installed equipment as is required to meet a 30-day rolling basis while operating at full load.

31. The MATS RTR sets a mercury limitation for lignite units without any technical basis that it can be met on a continuous basis, in general, and provides no compliance margin to account for the variability in unit performance and emissions control capabilities from unit to unit.

32. Basin Electric is irreparably harmed by the final MATS RTR because it is unknown if Antelope Valley and Leland Olds' existing mercury controls can achieve the New Mercury Limitation of 1.2 lb/Tbtu on a sustained basis at full load.

33. The Final Rule places Basin Electric in an impossible position, given the Rule's impending compliance date. Noncompliance with the Clean Air Act is not an option.

34. To have any possibility of meeting the New Mercury Limitation, Basin Electric must modify the existing system at both Antelope Valley and Leland Olds to produce a higher injection rate and make the systems more robust. Even though EPA has not demonstrated that the New Mercury Limitation will provide any health benefits, Basin Electric must complete this modification project to lower the emission rate. The modification costs and ongoing operation expenses are significant. Specifically, these technologies will require over

$4,000,000.00 in capital expenditures upfront for the four units collectively, as well as increased labor costs for installation, operation, and maintenance of the technology and equipment and associated training, along with additional sorbent injection, will result in increased operating costs over the long term. We must begin expending these dollars immediately, and certainly before the resolution of this case, in order to meet the deadlines set out in the Final Rule.

35. Costs to comply with the New Mercury Limitation are exorbitant and damage Basin Electric. Costs will be passed along to its member cooperatives and end users who are harmed via higher electricity prices. The capital and operational costs to Basin Electric, its member cooperatives, and end users cannot be recouped.

THE NEW FPM LIMITATION WILL CAUSE IMMEDIATE AND IRREPARABLE HARM TO THE ELECTRIC COOPERATIVES AND TO BASIN ELECTRIC

36. EPA's New fPM limit of 0.010 lb/MMBtu will require upgrades at Leland Olds and Laramie River.

37. Basin Electric's harm is immediate. Basin Electric would need to begin engineering and constructing, at a minimum, ESP upgrades at Leland Olds and Laramie River as soon as possible to have any

opportunity to meet the new compliance date for the MATS RTR. If ESP upgrades are required, Basin Electric would need 36 months to complete. It is likely that the 36-month estimate will be further protracted due to the lack of contractors available to perform the work.

38. If ESP upgrades were not sufficient, baghouse technology would be required. If a baghouse is required, Basin Electric would need approximately 48 months to convert to baghouse technology.

39. Costs of compliance with the New fPM Limitation are overly burdensome, for the following reasons.

40. ESP retrofits are expensive. They may cost an estimated $67,262 per fPM ton removed. *See* Cichanowicz Technical Report.

41. Baghouse installation is extremely costly. It is estimated to cost $282,715 per fPM ton removed. *See* Cichanowicz Technical Report.

42. Electric cooperatives have limited financial resources to undertake projects of this magnitude coincident with other environmental compliance projects.

43. To comply with the MATS RTR, Basin Electric is forced to take measures that immediately increase compliance and operational costs. The MATS RTR impacts Basin Electric's ability to supply

affordable, reliable energy to its customers. Added costs will place upward pressure on rates for rural customers, particularly when combined with the effects of EPA's other recent electric utility sector-focused rules.

THE MATS RTR CREATES GRID RELIABILITY CONCERNS

44. Lignite power plants, which provide a significant source of electric power in North Dakota, are important to the regional economy.

45. Thus, the Final Rule, with its reversal of EPA's position on lignite-fired sources, impacts North Dakota more profoundly than other areas of the country. These concentrated impacts affect the ability of the North Dakota utilities to maintain adequate generation resources.

46. Most (if not all) of the lignite plants in North Dakota must make some changes as result of the Final Rule. These changes will require an immense amount of coordination between different regulated facilities and likely involve serious risks to the reliability of electric grids providing power to the region while the removal equipment at each of the impacted facilities are taken offline to undergo the additions and upgrades required by the Final Rule.

47. The North American Electric Reliability Corporation has predicted continued future shortfalls in North Dakota.[1] The MATS RTR intensifies an already tenuous, overburdened grid in transition.

SUMMARY OF HARM TO BASIN ELECTRIC

48. Basin Electric is harmed because it must immediately commence costly compliance testing and project development to evaluate whether it can meet the MATS RTR emissions limits and applicable compliance deadline.

49. The MATS RTR could potentially cause Antelope Valley, Leland Olds and Laramie River which are dispatchable, reliable generating resources, to operate differently at a substantial cost and permanent loss to Basin Electric.

50. Even if the MATS RTR is overturned, the direct costs to Basin Electric, its member cooperatives, and end users cannot be recouped once spent. These damages are permanent.

* * * *

[Signature Follows on Next Page]

[1] NERC, 2024 Summer Reliability Assessment (May 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

I declare under penalty of perjury that the foregoing is true and correct.

Gavin A. McCollam

Dated: 6/5/2024

Exhibit 6

DECLARATION OF MIKE HOLMES
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, Mike Holmes, hereby declare and state under penalty of perjury that the following is true and correct to the best of my knowledge and is based on my personal knowledge or information available to me in the performance of my official duties:

1. My name is Mike Holmes, and my business address is 1016 Owens Avenue, Bismarck, North Dakota, 58502. I am over the age of 18, have personal knowledge of the subject matter, and am competent to testify concerning the matters in this declaration.

2. I have served as the Vice President of the Lignite Energy Council and the Director and Technical Advisor for North Dakota's Lignite Research, Development and Marketing program since December 2017. I am providing this declaration due to concerns about the closure of Lignite Energy Council member facilities which would cause irreparable harm to the regional industry and electricity consumers given the unachievable standards EPA has imposed upon these facilities.

3. The Lignite Research, Development and Marketing program This is a grant program focused on developing technology to optimize efficiency, control emissions, maintain reliability and low costs for the region's lignite generated baseload electricity. I have Bachelor of Science degrees in

mathematics and chemistry from Mayville State University, and a Master of Science degree in chemical engineering from the University of North Dakota. I have worked in technology development for over 35 years including project manager roles on multiple research and development projects focused on mercury capture spanning lignite, subbituminous, and bituminous coals.

4. I am submitting this declaration in support of Petitioners' Motion to Stay the Final Rule published by the U.S. Environmental Protection Agency (EPA) on May 7, 2024, entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 89 Fed. Reg. 38508 (Final Rule).

5. I have significant concerns that the Final Rule is based on inaccurate assumptions, and ignores the complex science associated with mercury capture from lignite coals in general and specifically North Dakota lignite.

6. In the Final Rule, EPA lowered the emission limit for mercury for Lignite-fired units from the current limit of 4.0 lb/10^{12} Btu to 1.2 lb/10^{12} Btu, even though technology hasn't been demonstrated to have reached the point of consistently achieving those levels of removal.

7. As support for the Rule, EPA relies heavily on two reports by Andover Technology Partners, one submitted to EPA in 2023 entitled "Assessment of Potential Revisions to the Mercury and Air Toxics Standards," Docket ID No. EPA-HQ-OAR-2018-0794 (June 15, 2023) ("Andover 2023 Report"), and one submitted to EPA in 2021 entitled "Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants," Docket ID No. EPA-HQ-OAR-2018-0794-4583 (Aug. 19, 2021) ("Andover 2021 Report") (together the "Andover Reports"). Because it wanted to ensure that EPA was using accurate facts as its justification for the Final Rule, the Lignite Energy Council (LEC) requested an independent review of EPA's reliance on the Andover Reports from RLR Consulting, LLC, submitted here as Exhibit A to my declaration (RLR Memorandum).

8. The major conclusions of the RLR Memorandum critique of the Andover Reports, with which I agree, include the following:

   a. *Control costs.* The Andover 2023 Report parrots EPA's clearly erroneous cost effectiveness result for its 800MW model plant of $8,703 per pound without providing any additional support for that conclusion. In its comments, the Lignite Energy Council (LEC) identified a significant math error in EPA's analysis and showed that a correct calculation even using EPA's aggressive assumptions would be $28,200 per pound of mercury removed. Lignite Energy Council Cmt. at 11, EPA-HQ-OAR-2018-0794-5957. EPA agreed and revised its analysis to a cost of $27,176. However, the Andover 2023 Report does not recognize EPA's original error or the correction EPA made in the final rule. Therefore, the cost-effectiveness conclusions made in the Andover 2023 Report remains demonstrably incorrect based on EPA's own admission.

b. *Control efficiency needed to comply and capability of facilities to meet such efficiencies.* The Andover 2023 Report claims EPA is correct that a control efficiency of 76-92% at lignite plants would be sufficient to comply with the Final Rule but provides no additional factual or analytical support for agreeing with that conclusion. The Andover 2023 Report also claims that compliance with those numbers is "well within" the capabilities of lignite fired plants because they are all equipped with scrubbers. These statements are clearly incorrect for several reasons explained in detail in the RLR Memorandum. In summary, the Andover 2023 Report merely assumes without analysis that the control efficiencies identified are achievable on lignite coal because the facilities have scrubbers. However, as noted in the RLR Memorandum, scrubbers are only effective at removing mercury from exhaust with high halogen (chlorine) levels such as bituminous, *not lignite or subbituminous* coal, because the halogens help oxidize the mercury into a form more easily captured in a scrubber. While both subbituminous and lignite facilities have low halogen levels, subbituminous facilities are able to use SCR to help oxidize the mercury to facilitate capture in a scrubber, whereas SCR is infeasible on North Dakota lignite. As previously recognized by the North Dakota Department of Environmental Quality, the low melting point and high alkaline metal levels of lignite ash causes masking, blinding, and deactivation, of the SCR catalyst and can plug the gas passages in the reactor in an extremely short period of time. The Andover 2023 Report fails to recognize these facts, rendering baseless its opinions on the effectiveness of emission controls at lignite facilities.

c. *SO_3 Levels.* EPA relies on the Andover 2021 Report to ignore the differences in SO3 levels among different coal types that can significantly affect the mercury control effectiveness of carbon injection controls systems. Specifically, EPA relies on the Andover 2021 Report to claim that there are commercially available advanced ‘‘SO3 tolerant’’ Hg sorbents and other technologies that are specifically designed for Hg capture in high SO3 flue gas environments. The only support for this statement is EPA's citation to Tables 8 and 9 in the Andover 2021 Report. However, RLR reviewed Tables 8 and 9 in that Andover report, and did not find any support for EPA's claim of SO3 tolerance because the high sulfur cases evaluated were only bituminous coals, not lignite. The RLR Memorandum provides information that the Andover 2021 Report ignores entirely. The RLR Memorandum notes that one of the major challenges in controlling mercury from combustion of lignite versus subbituminous coal is sulfur content. The higher (on average) sulfur content of lignite leads to the formation of sulfur trioxide (SO_3) in the combustion zone. The SO_3 in the flue gas competes with the mercury for adsorption sites on any injected activated carbon. Since the SO_3 concentration in the flue gas is on the order of parts per million (ppm) by volume while the mercury concentration is on the order of parts per trillion (ppt) by volume, SO_3 overwhelms the adsorptive capacity of activated carbon injection to control mercury emissions from lignite facilities. The Andover 2021 Report does not address these facts.

d. *Lower emission rates are achieved at a lower cost than higher emission rates.* The RLR Memorandum explains how the errors in the Andover 2023 Report summarized above result in the authors' counter-intuitive conclusion that greater emissions reductions will cost less to achieve. Moreover, as with the rest of the Andover Reports, none of the assumptions or equations that are used to produce its conclusions are shown so there is no way to replicate the calculations.

e. *Andover and sponsor bias.* Based on my review of the website for the organization that sponsored the Andover Reports, the reports could be potentially biased. The sponsor of the Report is an environmental group named Center for Applied Environmental Law and Policy (CAELP). As one example of the potential bias of CAELP, the organization publishes a podcast named "Volts" that is described by them as a "podcast about leaving fossil fuels behind."

f. *Bootstrapping by EPA and Andover.* Based on my review of the Andover Reports and the RLR Memorandum critiquing those Reports, it is my opinion that EPA's reliance on the Andover Report is bootstrapping, in three steps: (1) EPA made unsubstantiated claims in its proposal about how lignite could meet the standard designed for other coals, then (2) the Andover report paid for by a group dedicated to "leaving fossil fuels behind" indicates agreement with EPA's analysis and conclusions, but likewise without providing any factual support, and finally (3) EPA claimed in the final rule that the Andover Reports provide the factual support for its otherwise unjustified conclusions."

9. In addition, to my agreement with the major findings of the RLR Memorandum, the following points and additional information further confirm the challenges lignite-powered facilities will face in attempting to meet the new emission limits for mercury.

   a. The Andover 2023 Report states that the facilities all have either a baghouse or a scrubber, and then states that as a result, each of the lignite facilities is capable of well over 90% Hg capture when the pollution control devices are used in combination with the existing activated carbon injection (ACI) injection system. This statement is false for the reasons identified above—baghouses and scrubbers are far less effective at reducing mercury emissions from lignite facilities than other types of coals due to the lack of high halogen content and/or the infeasibility of installing SCR. I state this conclusion based on my on experience in evaluating the potential effectiveness of control measures installed on lignite facilities.

b. The Andover Reports refer to data and performance from non-lignite units. The performance from these cannot be compared to lignite fired systems, as is confirmed by existing data with lignite.

i. Wet scrubbers are not effective for mercury capture from flue gas containing high levels of elemental mercury, because of the low solubility and low reactivity.

ii. While additives such as halogens can promote mercury reactivity, the data has shown limits to their effectiveness in lignite-fired systems.

iii. Capture of mercury from lignite-fired systems with activated carbon (treated or untreated) gets significantly more challenging as percent removal increases. The report refers to algorithms and data from non-lignite systems that imply you can simply add more carbon to attain greater than 90% capture in lignite systems. This conclusion is not supported by data from lignite facilities.

10. In my opinion, the errors made in the Andover Reports, upon which EPA relies entirely for many of its determinations, result in the erroneous conclusion that the new mercury limit is achievable by cost-effective controls at lignite facilities. Once those errors are corrected, the data and

information available in the record for EPA's rule confirms the opposite conclusion—most lignite facilities cannot cost-effectively achieve the new mercury limit imposed by EPA and may not be able to achieve the limit at all, regardless of cost. This conclusion likewise confirms the declarations made by members of LEC that the new mercury limit presents a significant threat of forcing the premature closure of lignite-fired electric generating units, and that the timing of EPA's rule requires actions to address that threat immediately, resulting in harm to LEC's members.

Executed in Bismarck, North Dakota, on June 3, 2024.

Mike Holmes
Director and Technical Advisor
North Dakota Lignite Research
Development and Marketing Program

Exhibit 7

DECLARATION OF CHRISTOPHER D. FRIEZ

I, Christopher D. Friez, declare as follows:

1. My name is Christopher D. Friez, and I am the Vice President-Land, Associate General Counsel and Assistant Secretary of NACCO Natural Resources Corporation ("NACCO NR").

2. NACCO NR, a subsidiary of NACCO Industries, Inc., through its subsidiary North American Coal, LLC, mines and markets lignite coal primarily as fuel for power generation and provides selected value-added mining services for other natural resources companies. Its corporate headquarters is located in Plano, Texas near Dallas. NACCO NR operates surface lignite coal mines in North Dakota, Mississippi, and Louisiana.

3. NACCO NR is one of the United States' largest miners of lignite coal and among the largest coal producers in the country, producing approximately 23.9 million tons of lignite in 2023.

4. Because lignite has a higher moisture content and a lower heat content than other types of coal, and therefore cannot be transported long distances in a cost-effective manner, most lignite is sold to power plants adjacent or near to the producing mine. If a power plant served by a lignite mine closes, I am not aware of any reasonably viable new market opportunities for the lignite coal.

5. EPA's MATS rule ("MATS") will cause immediate, irreparable injury to NACCO NR, its workers, and the communities in which it mines coal in several ways. According to modeling analysis conducted by the North Dakota Transmission Authority ("NDTA"), dated April 3, 2024, a true and correct copy of which is attached as Attachment A, the changes required by MATS are likely not technologically feasible for lignite-based power generation facilities. The MATS rule eliminates the "units designed for low rank virgin

coal" subcategory established for lignite-powered facilities by causing these facilities to comply with the same mercury emission limitation that currently apply to electric generating units combusting bituminous and subbituminous coals. Numerous comments in the administrative record provide that the new emission standards are not technologically feasible and will impose crippling compliance costs that may require facility retirement. Even if compliance is technologically feasible, the added cost to comply, and unknown long term operational issues caused by the increased use of materials needed to comply, may cause plant retirements and mine closures. The EPA itself indicates, within the MATS rule, that the following plants, among others, will potentially be impacted by filterable particulate matter (fPM) and the mercury standard: Red Hills Generating Facility (MS; lignite); Antelope Valley Station (ND; lignite); Coal Creek Station (ND; lignite); Coyote Station (ND; lignite); Leland Olds (ND; lignite); and Spiritwood Station (ND; lignite). NACCO NR sells nearly all of its lignite coal production to these facilities. The retirement of these facilities would cause NACCO NR to close the coal mines which currently supply these facilities, resulting in the write off of tens of millions of dollars of investment by NACCO NR. These closures would result in hundreds of millions of dollars of stranded investment at these facilities and mines, much of which would likely be passed through to North Dakota and Minnesota ratepayers, cooperative members, and small municipalities. The closure of the Red Hills Mine would result in the loss of over $50 million of direct investment made by NACCO NR to date. In addition, early closure of these plants would result in the loss of over a thousand jobs and the loss of revenue which NACCO NR is contracted to receive well into the future. NACCO NR believes that all of these injuries are preventable if the court stays and ultimately overturns the rule.

North Dakota—Coyote Creek Mine

6. Through a wholly-owned subsidiary, Coyote Creek Mining Company, L.L.C. ("CCMC"), NACCO NR developed the Coyote Creek Mine in Mercer County, North Dakota, located about 70 miles northwest of Bismarck. The Coyote Creek Mine began making lignite deliveries to the 427-megawatt (MW) Coyote Station in 2016.

7. If Coyote Station cannot meet the requirements of the MATS rule, it will be required to close. The purpose of the Coyote Creek Mine is to support, and to provide a fuel source for, Coyote Station. Thus, if Coyote Station closes, Coyote Creek Mine would close as well. Mine closure would result in a layoff of the 90-person workforce, CCMC would go out of business, and the local community and the State of North Dakota would be deprived of the valuable attendant benefits and taxes and royalties described below in paragraphs 13 and 14.

8. To develop the mine and comply with its contractual obligations, CCMC permitted an area large enough to supply coal for the 25-year life of the contract with Coyote Station. CCMC spent over $6 million to permit the acreage needed for 25 years. If the power plant and mine must close in 2027, less than half of the acreage permitted will have been mined and CCMC will lose over $3 million in permitting costs spent to permit lands that will never be mined. In addition, $30 million of mine development costs are being amortized over the life of the mine. If that life is cut in half due to implementation of the MATS rule, another $15 million in such costs are lost.

9. In addition to permitting and mine development costs, CCMC incurred equipment costs of around $80 million to support mine startup and operation through the life of the mine. Again, these costs are being amortized over the life of the mine, and if the mine is forced to close early, nearly $40 million of those costs are lost because full amortization cannot

be realized. And the equipment will likely have a very low resale value because of the closure of other mines at the same time. Finally, if Coyote Station shuts down and the mine closes in 2027, the contractual arrangement between CCMC and the power plant owners requires CCMC to purchase the dragline and rolling stock for approximately $30 million, due to the early closure of the mine.

10. Due to the cost-plus nature of the contract under which CCMC supplies fuel to Coyote Station, many of CCMC's costs and obligations are passed through to the public utilities that jointly own Coyote Station—Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Company, and NorthWestern Corporation. In the end, the utilities, and more specifically their ratepayers and members, will pay these costs. In return, the ratepayers and members to whom the costs of Coyote Station are passed on will not have received the benefit of the low-cost and reliable power that otherwise would be delivered by Coyote Station. Their stranded investment in the Coyote Creek Mine will be lost.

North Dakota—Falkirk Mine

11. NACCO NR, through its wholly-owned subsidiary, The Falkirk Mining Company ("Falkirk"), operates the Falkirk Mine near Underwood, North Dakota, about 50 miles north of Bismarck. The Falkirk Mine annually produces between 7 million and 9 million tons of lignite for Coal Creek Station, a two-unit 1100-megawatt power plant owned by Rainbow Energy Center.
12. Coal Creek Station is impacted by the MATS rule.
13. A layoff at Falkirk Mine will be acute on numerous levels. According to an economic report prepared by North Dakota State University, a true and correct copy of which is

attached as Attachment B, in 2021, the latest year for which actual data is currently available, "The combination of coal mining, coal conversion, coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,300 direct jobs in North Dakota in 2021." "The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income." For the five hundred plus employees that stand to lose their jobs if Coal Creek Station closes, their lives, and their families' lives, may be drastically impacted.

14. Also, a shutdown would have a substantial impact across several counties and cities in North Dakota. Like all mining companies, Falkirk pays a coal severance tax of 37.5 cents on each ton of lignite mined. In 2023, Falkirk paid approximately $2,500,000 in coal severance taxes. NACCO NR's neighboring Freedom Mine paid approximately $4,500,000 in coal severance taxes. Under North Dakota law, 30% of revenue from the 37.5 cent tax is used to fund a Constitutional Trust Fund administered by the Board of University and School Lands. The other 70% is shared among the coal producing counties in the State, which is further apportioned as follows: 40% to the county general fund; 30% to the cities within the county, and 30% to the school districts. Absent a stay of the MATS rule, if these mines are forced to shut down, this will impact education, law enforcement, and social services throughout the State.

15. Even if the parties prevail in litigation efforts and the MATS rule does not ultimately go into effect, the MATS rule is already immediately impacting the operation of the mine to the detriment of the local community. At the Falkirk Mine, hiring decisions must be made with a long term vision in mind, and the decision to fill open positions or hire for new positions cannot be made with the current uncertainty the MATS rule creates. In addition, the uncertainty created by the MATS rule makes it difficult to attract and retain employees

who know they may not have a job in a few years. These difficulties are real and locations like the Falkirk Mine are experiencing them right now and will continue to experience them during the litigation of the MATS rule if a stay is not granted.

16. Decisions regarding large capital expenditures for equipment must be made years in advance due to the amount of time it takes to finance, acquire, transport, assemble and test equipment. A decision must be made now as to whether to acquire an additional dragline for the Falkirk Mine to meet customer demands and contractual obligations. A used dragline would need to be acquired now—at a cost of approximately $30 million—so the dragline can be purchased, transported, reconstructed and placed into service by late 2026 to meet these customer demands and contractual obligations. Due to their enormous size and complexity, it takes years for a used dragline to become operational at a new location. Draglines weigh millions of pounds and must be disassembled for transport (by rail and truck) to their new location. The parts and equipment constituting the dragline are transported in dozens of modular units to the new location. Upon arrival, the equipment is refurbished, re-assembled, erected, and tested. This work is done by private contractors, including truckers, welders, electricians, mechanical and electrical engineers, and software programmers.

17. Because of this extensive and time-consuming process, Falkirk must make a decision acquire to the $30 million dragline now, in order for the dragline to become operational by late 2026 to meet customer demand. If Falkirk makes this necessary decision and then is obligated to close the mine in 2027, it would lose almost all of its substantial investment in this piece of equipment, which will be worth only scrap value if the mine is shut down. Given the lead time required and the uncertainty created by the MATS rule, it is difficult to make an informed decision on such a large capital expenditure.

North Dakota – Coteau Freedom Mine

18. NACCO NR, through its wholly-owned subsidiary, The Coteau Properties Company ("Coteau"), operates the Freedom Mine near Beulah, North Dakota, about 75 miles northwest of Bismarck. The Freedom Mine annually produces between 12 million and 14 million tons of lignite for Antelope Valley Station ("AVS"), a two-unit 900-megawatt power plant, Leland Olds Station ("LOS"), a 660-megawatt power plant, and Dakota Gasification Company ("DGC"), a Synfuels plant, all owned by Basin Electric Power Cooperative.
19. AVS and LOS are both impacted by the MATS rule.
20. Similar to Falkirk, a layoff at Freedom Mine would be devastating to the local community. The combination of over 400 high paying jobs at the Freedom Mine alone, along with approximately 600 more at the combined facilities of AVS, LOS, and DGC are the backbone of a 100 mile radius of families' livelihoods and economic activity for central North Dakota, including the neighboring towns of Beulah and Hazen. Without the employment provided by these facilities, the towns of Beulah and Hazen could vanish, along with any economic activity in the region.
21. A shut down or curtailment of coal usage at AVS or LOS also affect the economics and operating costs of DGC. DGC enjoys a lower price for its lignite coal input based upon sharing in the volume of coal needed to operate AVS and LOS. Because of economies of scale and shared costs over a larger number of tons, if AVS and LOS are shut down, the coal costs for DGC increase exponentially, causing the economics of that facility to be strained as well.

22. NACCO NR, at its Freedom Mine, currently has about $130 million worth of property, plant, and equipment which would require accelerated depreciation if the mine is closed early because of the MATS rule. In addition to that, there is another $70 million in lease depreciation that would be unrealized, along with approximately $37 million in warehouse inventory that would have little to no value if the mine were closed early. Finally, a shut down of the Freedom Mine would result in a lost payroll of over $60 million annually.

23. Beyond the impacts of a shut down, the MATS rule is creating an immediate impact on the operation of the mine to the detriment of Coteau. At the Freedom Mine, as with Falkirk, decisions regarding large capital expenditures must be made years in advance due to the amount of time it takes to finance, acquire, transport, assemble and test equipment, and to determine how much and which types of equipment are necessary for different mine plans. There are numerous decisions relating to equipment purchases, repairs, mine plans and other capital requirements that must be delayed or decisions altered for short term requirements rather than long term decision-making, creating higher future costs and less efficient operations. Equipment purchases, or equipment maintenance, that are delayed pending the outcome of the MATS rule will add additional cost in the future. Additionally, Coteau is currently facing major mine plan decisions that depend on the length of time the mine will be in operation, but the uncertainty of the MATS rule (especially when coupled with the additional announced rules) causes great difficulty in making these decisions.

Mississippi

24. NACCO NR has owned and operated the Red Hills Mine near Ackerman, Mississippi, since 2002. On an annual basis, the Red Hills Mine produces approximately 2.4-2.8 million tons of lignite. Lignite from the Red Hills Mine is used as a fuel supply at the adjacent Red

Hills Generating Facility, a 440-megawatt power plant that provides electricity to the Tennessee Valley Authority.

25. Based on current projections, NACCO NR believes the Red Hills Generating Facility is particularly vulnerable to meeting the filterable particulate matter standard required by the MATS rule.

26. NACCO NR provides lignite to the Red Hills Generating Facility pursuant to a supply agreement that runs through 2032. The agreement, however, also includes two ten-year extension options that, if exercised, would extend the agreement to 2052.

27. Based on NACCO NR's geological data, there are enough proven lignite reserves in the vicinity of the Red Hills Mine to support mining until at least 2052. The most efficient way to mine the reserves would have been to shift approximately 6 miles of Mississippi Highway 9, which bisects the Red Hills Mine area in a north-south direction, about 2 miles to the east. However, because of previous regulatory uncertainty (much like the uncertainty that would result if the MATS rule is not stayed) the decision was made to cross Mississippi Highway 9 by constructing an underpass, rather than moving the highway. Similar operational decisions are made on a regular basis and, without a stay here, inefficient and shorter term decisions will be required. These decisions will collectively add up to significant and unnecessary financial harm.

28. NACCO NR currently has assets valued at over $50 million at the Red Hills Mine that will likely be lost as stranded investments if the MATS rule is implemented.

29. The effects of the MATS rule cannot be considered in a vacuum. EPA promulgated revisions to the New Source Performance Standards rule (greenhouse gas emissions requirements) on May 9, 2024 that require significant reductions in emissions from coal-fired power plants, including requirements for carbon capture and storage or co-firing on

alternative fuel sources, or shut down by January 1, 2032. Unfortunately, in addition to numerous other issues, the compliance dates for the two rules are misaligned. To comply with the fPM and/or mercury standards, power plants need to decide whether to spend the significant capital required to attempt to comply with MATS, if compliance is even possible, while at the same time weighing whether they can even operate past January 1, 2032 anyway. If facilities must presume they are required to shut down before January 1, 2032 anyway, it is unlikely they will invest capital to comply with the MATS rule.

30. Finally, absent a stay of the MATS rule and facing significant compliance costs over a very short implementation timeframe (if compliance is even technologically feasible), coupled with the effect of the other rules as mentioned above, a number of facilities are expected to elect not to install additional control equipment and emission monitors. If the rule is not stayed, facility owners may decide to shut down or curtail output rather than spend significant dollars with such an uncertain outcome, and NACCO NR will suffer tremendous immediate harm.

31. I, Christopher D. Friez, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct to the best of my knowledge.

Christopher D. Friez
NACCO Natural Resources Corporation

Dated: May 30, 2024

Attachment A

to the Declaration of Christopher D. Friez

[redacted]

Analysis of

Proposed EPA MATS Residual Risk and Technology Review and

Potential Effects on Grid Reliability in North Dakota

Claire Vigesaa, Director

North Dakota Transmission Authority

April 3, 2024

Assisted by:

Isaac Orr and Mitch Rolling

Center of the American Experiment

Contents

Executive Summary

On behalf of the North Dakota Transmission Authority (NDTA), the Center of the American Experiment prepared this study to analyze the potential impacts of EPA's proposed revisions to the Mercury and Air Toxics Standards (MATS) Rule on North Dakota's power generation and power grid reliability.

Our primary finding, which is drawn substantially from the Rule's administrative record, is that the proposed changes are likely not technologically feasible for lignite-based power generation facilities, will foreseeably result in the retirement of lignite power generation units, and will negatively impact consumers of electricity in the Midcontinent Independent Systems Operator (MISO) system by reducing the reliability of the electric grid and increasing costs for ratepayers.

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

Moreover, building such replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Replacing these lignite facilities with new wind, solar, natural gas, and battery storage facilities would cost an additional $1.9 billion to $3.8 billion through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts. Accounting for projected increases in demand for electricity, we assess that if the MATS Rule goes into effect in the near future, by 2035, the MISO grid will experience up to an additional 73,699 megawatt hours (MWh) of unserved load, with an economic cost of up to $1.05 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Section A: North Dakota's Power Environment

North Dakota Transmission Authority (NDTA)

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

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

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

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

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

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

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

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

FERC-Recognized Regional Transmission Organizations and Independent System Operators

(www.ferc.gov)

Generation Adequacy, Transmission Capacity & Load Forecast Studies

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

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

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

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

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

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

Current North Dakota Generation Resources

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

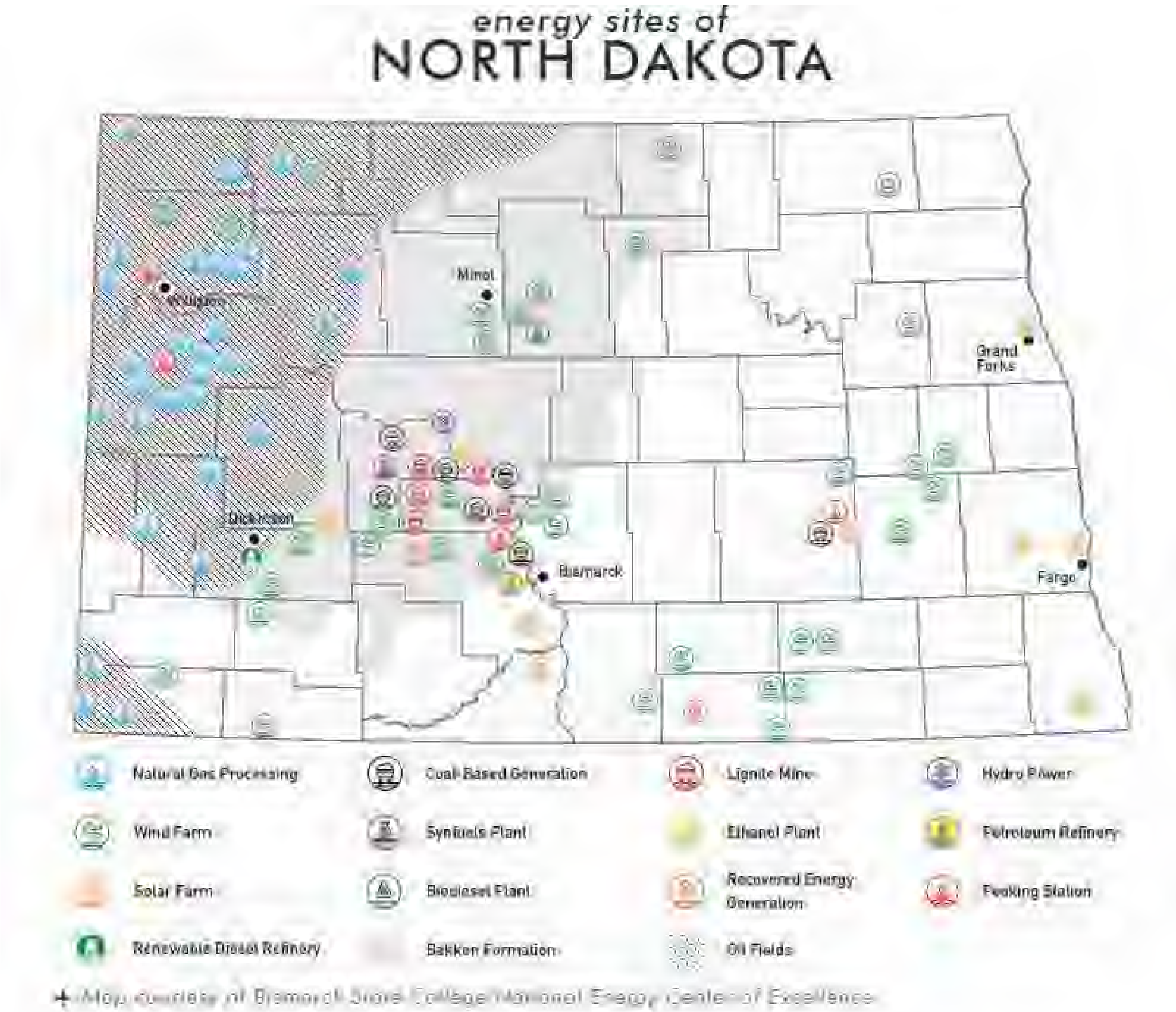
1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW since it is intermittent. This is representative of the

amount that is estimated to be available for the peak demand in the summer.

- Solar Generation: Although North Dakota currently lacks utility-scale solar generation facilities in operation, some projects are in the queues of regional transmission organizations like MISO and SPP, indicating potential future development in this area.

2. Thermal Coal Generation:
   - North Dakota currently operates thermal coal generation at six locations, comprising a total of 10 generating units with a combined capacity of approximately 4,048 MW.
   - The average capacity factor for these generating plants ranged from 65% to 91% in 2021, excluding the retired Heskett Station.
   - Rainbow Energy operates the Coal Creek Station and the DC transmission line that transports ND produced energy to the Minneapolis region. Rainbow Energy is assessing a CO2 capture project for the facility. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity on the DC line.
3. Hydro Generation:
   - North Dakota has one hydro generation site equipped with 5 units, boasting a total capacity of 614 MW.
   - However, the average capacity factor declined to approximately 43% in 2021 due to limitations imposed by water flow in the river, particularly during drought years.
4. Natural Gas Generation:
   - North Dakota operates three sites for electric generation utilizing natural gas, comprising 21 generating units with a total capacity of 596.3 MW.
   - These units include reciprocating engines and gas turbines, with variation in summer capacity influenced by the performance of gas generators in hot weather.
   - Total natural gas generation in North Dakota remained steady from 2019 through 2021, amounting to 1.445 GWhr in 2021.
5. Total Generation:
   - The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW.
   - Wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW due to its intermittent nature, down from 4,250MW of installed capacity, representing the estimated amount available during peak summer demand. However, newer installations have demonstrated slightly higher capacity for accreditation.

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

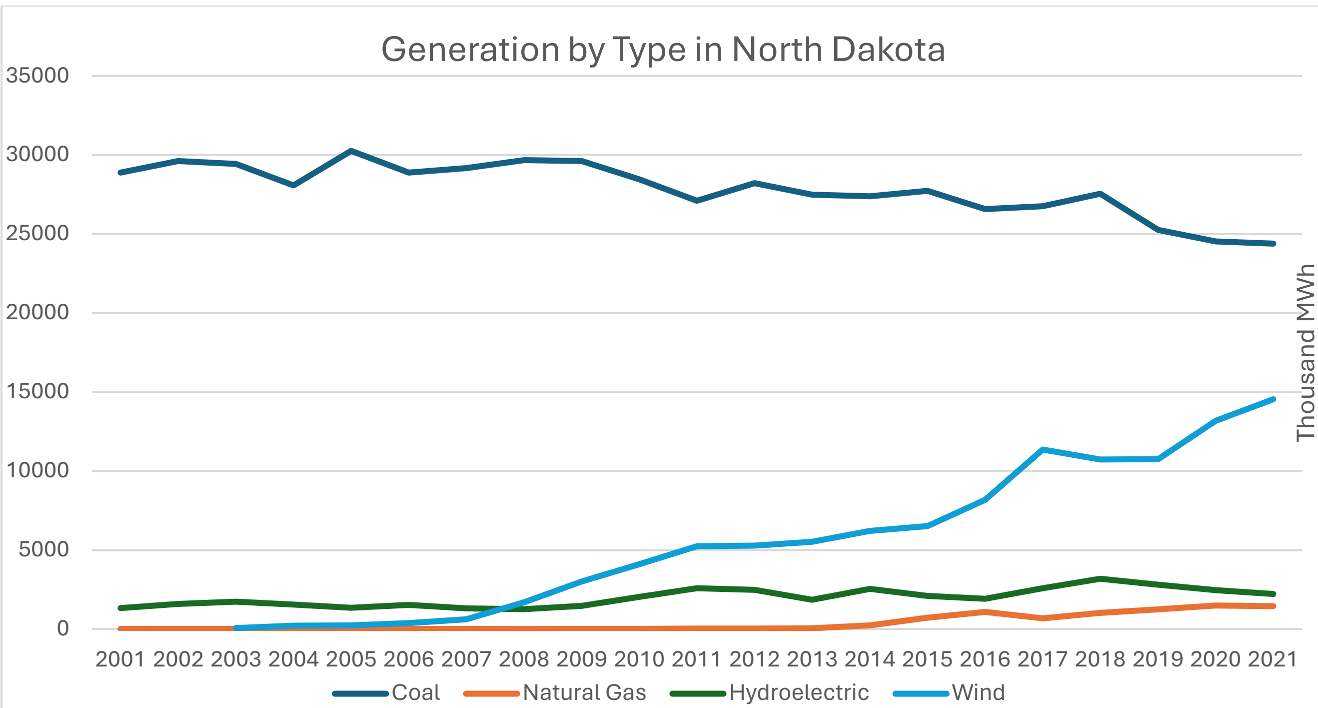


Electric Generation Market & Utilization

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

According to data from the Energy Information Administration, in 2020, North Dakota generated a total of 42,705 MWh of electricity from all sources, with 46% of this total being exported beyond the state's borders over two large high voltage direct current lines (HVDC), which serve load in the neighboring state of Minnesota and multiple 345kv and 230kv alternating current (AC) transmission lines serving surrounding states. Wind generation accounted for 31% of North Dakota's total electricity generation in 2020, highlighting the growing significance of renewable energy in the state's energy portfolio. Notably, industrial demand in North Dakota experienced substantial growth, expanding by nearly 11% in 2020.

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



Grid Resource Adequacy and Threats to Growth Opportunities

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

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

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

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

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

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

Grid Reliability Is Already Vulnerable

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

NERC's 2023 Reliability Risk Assessment

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

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

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

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

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

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

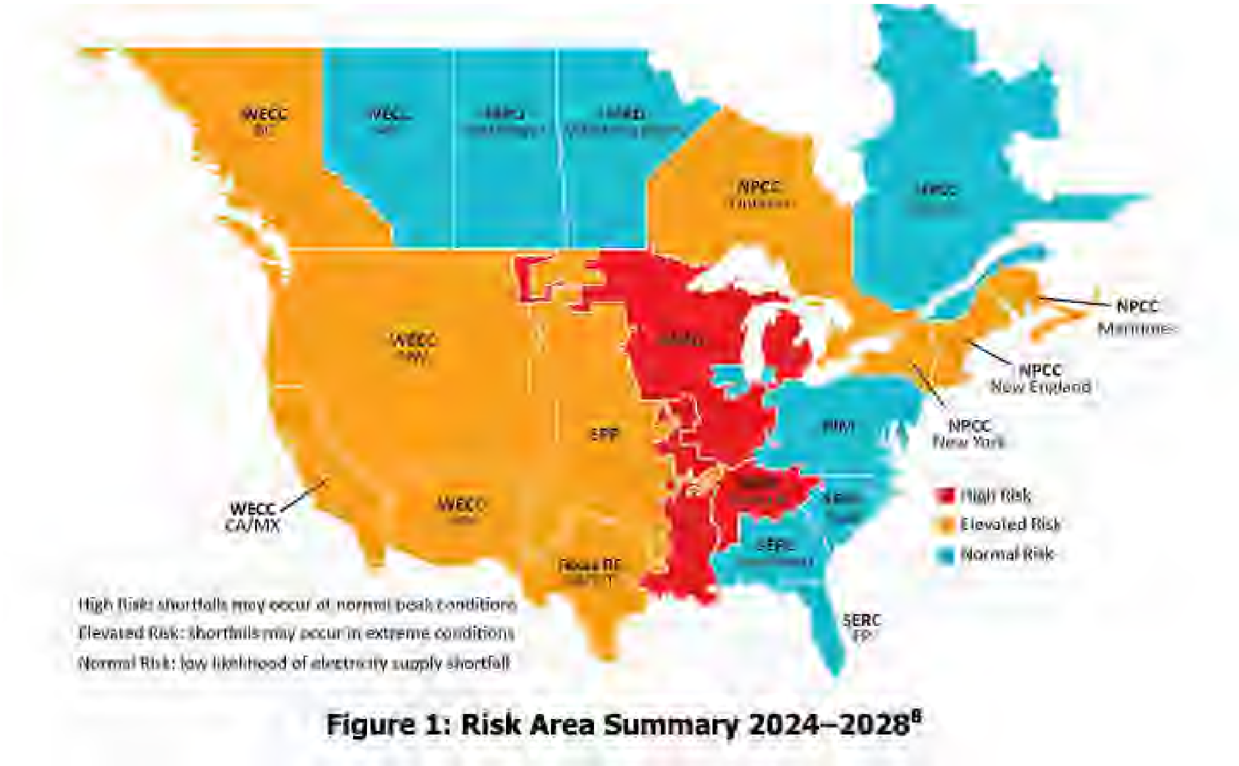

Figure 1: Risk Area Summary 2024–2028[8]

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

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

MISO's Response to the Reliability Imperative (2024)

On February 26, 2024, the Midcontinent Independent System Operator (MISO) released "MISO's Response to the Reliability Imperative[4]," a report which is updated periodically to reflect changing conditions in the 15-state MISO region that extends through the middle of the U.S. and into Canada. MISO's new report explains the disturbing outlook for electric reliability in its footprint unless urgent action is taken. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliability attributes.

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

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

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

margin requirements.[5]

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

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

> *"While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability.* ***In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.***
>
> *In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.*
>
> *MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline.* ***If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*** *The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources*."

Despite these reliability warnings issued by MISO, EPA did not consider the reliability impacts of the proposed MATS rules required emission control upgrades and additions to units. It is likely that many units that would have to incur millions of dollars to retrofit emissions controls to comply with this proposal would not do so.[6]

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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

[6] Rae E. Cronmiller, "Comments on Proposed National Emission Standards for Hazardous Air Pollution: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," The National Rural Electric Cooperative Association, June 23, 2023, Attention Docket ID NO. EPA-HQ-OAR-2018-0794.

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

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

The escalating frequency of grid events requiring emergency procedures, such as the 48 Maximum Generation events in MISO since 2016 and the increasing number of alerts issued by SPP, over 194 alerts issued in 2022, underscores the urgency of addressing transmission congestion and bolstering reliable generation capacity. The economic growth and security of North Dakota are directly tied to the timely development of new transmission facilities in tandem with dependable dispatchable electric generation.

The impacts of grid strain extend beyond the energy sector, affecting multiple industries, ratepayers, and overall economic stability. Volatile wholesale prices and transmission congestion undermine business operations and investment confidence, hindering economic growth and prosperity. Moreover, reliable electricity supply is critical for essential services, including Department of Defense facilities, underscoring the broader implications of grid reliability issues. Achieving a balanced generation portfolio requires careful consideration of reliability and resilience under all weather conditions, especially amidst the electrification of America and the imperative to safeguard public welfare and security.

Additionally, over 50% of the electricity generated in North Dakota is exported to neighboring states, magnifying the ripple effects of any regulations impacting dispatchable electricity generation resources. By responsibly managing the generation portfolio and prioritizing generation adequacy, North Dakota and the nation can seize significant opportunities for economic growth, innovation, and sustainable development.

Section B: The Proposed MATS Rule Will Dramatically Affect North Dakota Lignite Electric Generating Units

The revised MATS Rule includes a proposal to eliminate the "low rank coal" subcategory established for lignite-powered facilities by requiring these facilities to comply with the same mercury emission limitation that currently applies to Electric Generating Units (EGUs) combusting bituminous and subbituminous coals, which is 1.2 pounds per trillion British thermal units of heat input (lb/TBtu). EPA's proposal is a substantial lowering of the current mercury limitation for lignite fired EGUs, which is 4.0 lb/TBtu.[7,8] The proposal also includes a significant reduction in the particulate matter standard applicable to all existing units from 0.03 lb/mmBtu to 0.01 lb/mmBtu. Because North Dakota is somewhat unique to the degree in which its power generation relies upon lignite coal, the compliance costs for this Rule, while likely to substantial for coal plants all around the country, will be most acutely inflicted upon North Dakota's lignite-based power generation facilities.

Numerous comments in the administrative record, including from the regulated facilities in North Dakota and the North Dakota Department of Environmental Quality, provided EPA with notice that the new emission standards are not technologically feasible, will impose crippling compliance costs that may require facility retirement, and will result in a significant portion of the dispatchable power provided by coal-generation facilities being taken off the grid. This report will summarize some of those concerns in the section that follows, however, a full study of the technological feasibility of complying with the new emissions standards is beyond the scope of this report. For purposes of this report, we assume the regulated facilities and state regulator were forthright in their concerns about the feasibility of lignite-based facilities meeting the new standards.

The Proposed MATS Rule Eliminates the Lignite Subcategory for Mercury Emissions

Although the Proposed Rule affects all coal electrical generating utilities (EGUs), reducing the lignite emissions standards to levels of other coal ranks effectively eliminates the lignite sub-category and would have drastic consequences for North Dakota's lignite EGU industry.[9] EPA original decision to regulate separately a subcategory of lignite units was well-supported with documented information and a thorough analysis. In its comments filed in this Docket, on June 22, 2023, the North Dakota Department of Environmental Quality (hereafter DEQ) encouraged EPA to review that prior determination and reaffirm the need for a lignite subcategory and the associated emissions standards.[10]

Specifically, DEQ summarized the original MATS proposal in 2011 and final MATS rule in 2012, in which EPA presented a body of evidence in support of the lignite category. For example, the EPA wrote:

> "For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter free

[7] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review,* 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[8] [8] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal-and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, (June 2, 2023) ("Cichanowicz Report").

[9] EPA characterizes lignite as "low rank virgin coal". 88 Fed. Reg. 24,854, 24,875. For this comment letter, lignite will be used in place of low rank virgin coal.

[10] David Glatt, P.E., "Comments on the Proposed Rulemaking Titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Docket ID No. EPA-HQOAR-2018-0794)," On Behalf of the North Dakota Department of Environmental Quality, June 22, 2023.

> basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units.
>
> The boiler of a coal-fired EGU designed to burn coal with that heat value is larger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories."

As explained by DEQ, EPA has not provided any scientific justification to support abandoning the lignite subcategory and requiring those facilities to comply with the emission standards applicable to other coal types. The most EPA identified in support of its proposal was a reference to information nearly 30 years old, which predated EPA's original determination.

The Proposed MATS Rule Will Not Provide Meaningful Human Health or Environmental Benefits

Section 112(f)(2) of the CAA directs EPA to assess the remaining residual public health and environmental risks posed by hazardous air pollutants (HAPs) emitted from the EGU source category.[11] Further regulation under MATS is required only if that residual risk assessment demonstrates that a tightening of the current HAP emission limitations is necessary to protect public health with an ample margin of safety or protect against adverse environmental effects.

When reviewing whether to revise the MATS Rule, EPA determined that further regulation of mercury and other HAPs would be unnecessary to address any remaining residual risk from any affected EGU within the source category. The stringent standards based on state-of-the-art control technologies that are currently imposed on coal-fired EGUs have already achieved significant reductions in HAP emissions. As EPA itself noted, the MATS rule has achieved steep reductions in HAP emission levels since 2010, including a 90 percent reduction in mercury, 96 percent reduction in acid gas HAPs, and an 81 percent reduction in non-mercury metal HAPs.[12]

Data from EPA and the U.N Global Mercury Assessment show mercury emissions from U.S. power plants are now so low they accounted for only 0.12 percent of global mercury emissions in 2022, assuming all other sources remained constant at 2018 levels.[13] These data demonstrate that

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[11] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[12] Fact Sheet, *EPA's Proposal to Strengthen and Update the Mercury and Air Toxics Standards for Power Plants*, *https://www.epa.gov/system/files/documents/2023-04/Fact%20Sheet_MATS%20RTR%20Proposed%20Rule.pdf*

[13] United Nations, "Global Mercury Assessment 2018," UN Environment Programme, August 21, 2019, https://wedocs.unep.org/bitstream/handle/20.500.11822/27579/GMA2018.pdf?sequence=1&isAllowed=y

US mercury emissions from power plants are lower than global cremation emissions, and North Dakota coal facilities emitted 9.25 times less mercury in 2021 than global cremations in 2018.[14]

[illegible]		
Category	US Tons	Percent of Global Emissions
Artisanal and small-scale mining	[illegible]	[illegible]
Global stationary combustion of coal	517.45	21.16
Non-ferrous metals production	359.72	14.69
Cement production	256.40	10.49
Waste from products	161.63	6.61
Vinyl chlorine monomer	64.09	2.62
Biomass burning	57.05	2.33
Ferrous metals production	43.89	1.79
Chlor alkali production	16.66	0.68
Waste incineration	16.44	0.67
Oil refining	15.81	0.65
Stationary combustion of oil and gas	7.84	0.32
Cremation	[illegible]	0.17
US stationary combustion of coal	[illegible]	[illegible]
North Dakota coal combustion	0.46	0.018

As the above chart indicates: the annual mercury emissions from global cremations (where the mercury primarily comes from individuals with dental fillings) exceed the mercury annually emitted by all coal-fired EGUs in the United States combined, and is orders of magnitude more than the mercury emissions from all coal-fired EGUs in North Dakota.[15]

Moreover, the Administrative Record indicates EPA has performed a comprehensive and detailed risk assessment that clearly documents the negligible remaining residual risks posed by the very low amount of HAPs now being emitted by coal-fired EGUs. EPA first performed that risk assessment in 2020, which concluded that "both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of

[14] ERM Sustainability Initiative, "Benchmarking Air Emissions of the 100 Largest Power Producers in the United States," Interactive Tool, accessed February 29, 2024, https://www.sustainability.com/thinking/benchmarking-air-emissions-100-largest-us-power-producers/

[15] UN Environmental Programme. (2018). Global Mercury Report 2018, Technical Background Report to the Global Mercury Assessment. https://www.unenvironment.org/resources/publication/global-mercury-assessment-technical-background-report

acceptability" for protecting public health with an adequate margin of safety.[16] Similarly, EPA's risk assessment supports the conclusion that residual risks of HAP emissions from the EGU source category are "acceptable" for other potential public health effects, including both chronic and acute non-cancer effects.[17]

These conclusions have been confirmed by the detailed reevaluation of the 2020 risk assessment that the Agency is now completing as part of the current rule-making action. That EPA reevaluation clearly demonstrates that the 2020 risk assessment did not contain any significant methodological or factual errors that could call into question the results and conclusions reached in the 2020 risk assessment. Most notably, EPA used well-accepted approaches and methodologies for performing a residual risk analysis that adhere to the requirements of the statute and are consistent with prior residual risk assessments performed by EPA over the years for other industry sectors.[18]

The results from both residual risk assessments can lead to only one rational conclusion: the current MATS limitations provide an ample margin of safety to protect public health in accordance with CAA section 112.

The DEQ filed comments addressing these points and asking EPA to provide a better health benefit justification than the rationale currently included in the Regulatory Impacts Analysis (RIA).[19] In particular, DEQ noted that EPA cannot rely on non-HAPs' co-benefits to justify the Proposed Rule, and EPA has not identified any HAP-related benefits that would be sufficient to justify the Proposed Rule. The agency also voiced skepticism over what it called EPA' s suspect characterization of the health benefits that it identified, which is quoted below:

> While the screening analysis that EPA completed suggests that exposures associated with mercury emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers.[20]

DEQ's well-founded concern is that EPA's admission that current exposure associated with mercury is below levels of concern is directly inconsistent with, not support of, EPA's proposal for a lower standard.

DEQ commented that this theme, unfortunately, is consistent across the entire "Benefits Analysis" section of the RIA, citing another example of this inconsistency, which is quoted below:

> "Regarding the potential benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively

[16] 88 Fed. Reg. at 24,865.
[17] *Id*. at 24,865-66.
[18] 88 Fed. Reg. at 24,865.
[19] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.
[20] *Id.* At p. 0-8.

> ....Overall, the uncertainty associated with modeling potential of benefits of mercury reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates-though importantly such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including methylmercury exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-mercury metal HAP were not expected to exceed acceptable levels, although we note that these emissions reductions should result in decreased exposure to HAP for individuals living near these facilities."[21]

Comments filed by the Lignite Energy Council (LEC) further emphasize the point. LEC stated that according to the risk review EPA conducted in 2020, which EPA has proposed to reaffirm, the risks from current emissions of hazardous air pollutants (HAP) emitted by coal-fired power plants are several orders of magnitude below what EPA deems sufficient to satisfy the Clean Air Act.[22] LEC points out that EPA has for decades found risks to be acceptable with an ample margin of safety if maximum individual excess cancer risks presented by any single facility is less than "100-in-1 million." In comparison, EPA's analysis of the coal- and oil-fired electric utility source category recognizes the risk it presents is now at one tenth of that acceptable level, with a maximum risk from any individual facility of "9-in-1 million."

However, even that value vastly overstates the risk associated with coal-fired power plants. The "9-in-1 million" risk level identified by EPA is only associated with a single, uncontrolled, residual oil-fired facility located in Puerto Rico.[23] What EPA's discussion of risk fails to recognize, but its analysis clearly shows, is that the highest level of risk presented by any coal-fired power plant is actually "0.3-in-1 million," more than 300 times lower than the threshold EPA deems acceptable.[24]

The level of risk presented by North Dakota lignite-powered plants is lower still. According to EPA's risk review, the maximum risks presented by any North Dakota lignite-fired power plant is "0.08-in-1 million," yet another order of magnitude lower than the highest risk from any coal-fired plant, and more than three orders of magnitude lower than EPA's "acceptable" level of risk with an "ample margin of safety."

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[21] *Id.* at pp. 4-1 - 4-2.

[22] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[23] *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, Docket ID No. EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019) ("Risk Assessment") (note that Table 2a is printed upside down in the final September 2019 version of the Residual Risk Assessment posted at www.regulations.gov, which may interfere with search commands; a searchable version of the same table is available in the December 2018 draft version, Docket ID No.). *See also* 84 Fed. Reg. at 2699 ("There are only 4 facilities in the source category with cancer risk at or above 1-in-1 million, and all of them are located in Puerto Rico.").

[24] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

The risks from North Dakota lignite are so low that they are more easily expressed, not in a million, but in a ***billion***—EPA has determined that the excess cancer risks from all North Dakota lignite plants fall between 5- and 80-in-1 billion.[25] Moreover, EPA's analysis indicates that those maximum risks are not associated with mercury.[26]

In fact, EPA's own analysis confirms the risks from North Dakota lignite-powered plants are so low they are little more than a rounding error that does not even qualify as a significant digit. In its analysis of the still low but relatively higher risk from the Puerto Rican oil-fired plants, EPA determined that one of those facilities presented a risk no greater than "1-in-1 million," even though EPA's modeling actually returned a risk level of "1.**09**-in-1 million."6 EPA discarded the extra ".09," apparently finding it too small to matter. However, that extra ".09" risk equates to "90-in-1 billion," and it is therefore higher than the ***entire*** risk identified for any North Dakota lignite plant.

The Administrative Record Indicates the Mercury Standard of 1.2 lb./TBtu is Technically Unachievable for EGUs using North Dakota Lignite Coal

The Administrative Record for the proposed rule suggests EPA made numerous critical mistakes in assuming lignite fired EGUs can achieve a 1.2 Hg/lb limit with 90% Hg removal. As detailed in the Cichanowicz Report, Section 6, EPA assumed the characteristics of lignite and subbituminous coals are similar such that the Hg removal by emission controls capabilities is similar. In this light, EPA did not consider that the high presence of sulfur trioxide (SO3) in lignite coal combustion flue gas that significantly limits the Hg emissions reduction potential of emissions controls.[27]

Similarly, as noted by LEC, EPA's proposal references data obtained via an information collection request as indicative of the level of performance achievable at North Dakota lignite facilities, but that data only reflects relatively short-term testing that does not fully capture the significant variability of lignite coals. Also, unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, all North Dakota lignite units are located at mine-mouth facilities without access to other coal types, and therefore depend entirely on the fuel extracted from the neighboring mine. As a result, changes in constituents between seams of lignite coal can result in a high level of variability in the emission rates that result from use of the coal as it is mined over time.[28]

While LEC agreed with EPA that the injection of activated carbon is the most effective means of reducing mercury emissions from lignite-powered units, LEC also criticized EPA for ignoring the well-known diminishing returns of injecting more carbon. With each marginal increase in carbon

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[25] Risk Assessment, Tbl. 2a (indicating cancer risks of 8.07e-08, 3.09e-08, 1.31e-08, 1.21e-08, and 5.12e-09 for Facility NEI IDs 380578086511, 380578086311, 380558011011, 380578086511, 380578086611 (Milton R. Young, Leland Olds, Coal Creek, Antelope Valley, and Coyote).

[26] *Id*., at Tbl. 2a (indicating the target organ of the risk associated with the plants identified in note 5 is "respiratory").

[27] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[28] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

injection, the incremental increase in emission reduction capability falls. Thus, injecting more and more carbon will not necessarily result in greater emission reductions beyond a certain injection level. LEC asked EPA to evaluate the effect of diminishing returns on its conclusion that North Dakota lignite-powered facilities can achieve the standard designed for all other units of 1.2 lb/TBtu.

EPA does not appear to have taken the above concerns into account in claiming lignite- powered facilities can achieve the performance levels achieved at subbituminous plants. As a result, EPA has significantly underestimated the level of control needed to achieve the proposed standard of 1.2 lb/TBtu. Contrary to the analysis EPA relies upon to justify lowering the standard for lignite plants, control efficiencies of greater than 90 percent would be needed for North Dakota lignite-powered facilities.[29] LEC's comments asked EPA to reconsider its proposal in light of these concerns, and in light of EPA's legal obligation to ensure all standards are "achievable," which means they "must be capable of being met under most adverse conditions which can reasonably be expected to recur."[30]

The Administrative Record indicates a key reason why EPA's proposed standards are unachievable is the chemical composition of North Dakota lignite. For example, lignite has different heat and moisture content than subbituminous coals. As a result, a greater volume of fuel and air is needed at lignite plants to produce the same heat input compared to subbituminous plants. Due to higher fuel and air flows, a much greater volume of sorbent is needed to achieve similar emission reductions, and the additional sorbent dramatically increases cost, and therefore reduces the cost-effectiveness, of the controls.[31]

Another distinguishing difference EPA appeared to overlook in its proposal is the higher sulfur concentration in North Dakota lignite relative to subbituminous Powder River Basin coal, which in turn produces a higher level of sulfur trioxide ("SO3"). In the past, EPA has worked with a consultant that recognized this reality as follow:

> With flue gas SO3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.[32]

Cichanowicz et al. highlighted this passage from the S&L technology assessment and also noted that the presence of SO3 often affects capture rates in another way—by requiring units with measurable SO3 to be designed with higher gas temperature at the air heater exit to avoid corrosion that would otherwise occur if the SO3 is allowed to cool and condense on equipment

[29] Cichanowicz Report, at 25, Table 6-1.
[30] *White Stallion Energy Center, LLC v. EPA*, 748 F.3d 1222, 1251 (2014) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n. 46 (D.C. Cir.1980)).
[31] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.
[32] Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology*, Project 12847-002, at 3 (Mar. 2013).

components. However, that higher exit gas temperature also impacts the effectiveness of sorbent injection systems—special-purpose tests on a fabric filter pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[33] The higher levels of SO_3 formed by the higher sulfur content found in lignite fuels will inhibit the ability of injected sorbents to reduce mercury emissions at lignite plants to a far greater extent than at subbituminous plants.

LEC agreed with these concerns in its comments and raised another important consideration — the fact that, unlike subbituminous plants, selective catalytic reduction (SCR) is technically infeasible on North Dakota lignite, due to its chemical composition. Although SCR systems are primarily installed for the control of nitrogen oxides (NO_X), SCR can enhance the oxidation of elemental mercury (“Hg^0”) which facilitates removal in downstream control equipment, such as wet flue gas desulfurization (FGD) systems.[34] The higher level of mercury control achievable with an SCR is almost certainly why the one lignite plant (Oak Grove) evaluated by EPA as part of its review of the MATS RTR appears capable of achieving the mercury limit set for other coal ranks—it has an SCR that cannot be installed on North Dakota lignite facilities.[35]

LEC’s comments also highlighted the experience of two LEC members that recently evaluated the difference in mercury control achieved by plants using subbituminous coal equipped with an SCR and plants using lignite coal without an SCR. Based on those evaluations, North Dakota lignite-powered facilities were found to have much greater difficulty reducing mercury emissions, despite using more than three times the amount of halogenated activated carbon than the subbituminous plant.

In the past, EPA has questioned whether SCR is technically feasible for North Dakota lignite-powered facilities, and recent research has confirmed that the significant challenges associated with using SCR on North Dakota lignite remain unresolved.[36] Although SCR has been demonstrated on the types of lignite found in other parts of the country, North Dakota lignite differs substantially in chemical makeup because it contains a much higher concentration of alkali metals (*e.g.*, sodium and potassium) that render the catalyst ineffective.[37]

In particular, the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 µm. As a vapor or as a very small particle, the sodium will pass through any upstream emissions control equipment (*e.g.*, electrostatic precipitators and scrubbers), and thus will reach the SCR regardless of whether the SCR is located before other emission control devices (high-dust configuration) or after those other controls (low-dust or tail-end configurations).[38]

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[33] Sjostrom 2016.

[34] 88 Fed. Reg. at 24875.

[35] Jason Bohrer, “Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[36] *See* Draft SIP, App. D, at D.2.c-5 (citing Benson, Schulte, Patwardhan, Jones (2021) “The Formation and Fate of Aerosols in Combustion Systems for SCR NO_X Control Strategies” A&WMA’s 114th Annual Conference, #983723).

[37] *Id.*

[38] *Id.*

Once the sodium particles reach the SCR, they plug the pores of the catalyst, which are the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive. Recent efforts to address these concerns through either cleaning or regeneration of the catalyst have not been successful, even at pilot scale. A study recently cited by DEQ in its regional haze plan provides additional details on these efforts and the unsolved technical challenges that remain regarding the impact of alkali metals in North Dakota lignite on the technical feasibility of SCR.[39]

According to LEC, its members report that efforts to identify a willing vendor for an SCR on a North Dakota lignite unit have been unsuccessful—all vendors have declined to offer SCR for use on North Dakota lignite once they have closely reviewed the unique characteristics that make SCR infeasible on that particular fuel.[40]

In short, the Administrative Record and other available evidence indicates that North Dakota lignite-powered facilities will likely not be able to meet the revised emission standards EPA is proposing for the MATS Rule.

The Administrative Record Indicates the Lower PM Standard May Also Not Be Technically Feasible

In addition to imposing a more stringent mercury standard on lignite by essentially eliminating the subcategory, EPA's proposal also lowers the standard on fPM for all existing units to the level previously deemed achievable only by new units. However, like its proposed Hg standard for lignite, EPA's proposal to revise the PM standard for all coal types remains unjustified by any demonstration of potential human health or environmental benefits.

The LEC's comments detail particular concerns associated with EPA's failure to provide a reasonable justification for so dramatically reducing the PM limit.[41] As LEC noted, the risks that the MATS Rule is designed to address have already been eliminated, down to several orders of magnitude below the level at which Congress directed EPA to stop regulating. The highest residual risk for the entire source category, which is based on an oil-fired unit, is just one tenth of EPA's acceptable level of risk, and the highest risk from any coal plant is more than an order of magnitude below the risk presented by oil-fired units.

Furthermore, the Administrative Record suggests that EPA's analysis of the achievability of the new 0.01 lb/mmBtu standard is based on an arbitrary data set, and that analysis also suffers from a lack of transparency. Specifically, commenters observed that EPA relies on a Sargent & Lundy memorandum that lacks sufficient detail or supporting documentation to verify the assumptions made, essentially hiding much of the agency's thought process behind the claim that the

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[39] *Id.*

[40] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[41] *Id.*

information on which it is based is not available in public forums.[42] In doing so, EPA seemingly commits what it has previously cited as error in plans developed by states and industry—failing to provide sufficient information to understand the reasoning underlying key conclusions.[43]

Moreover, the Administrative Record indicates the combined effect of both the proposal to require universal use of CEMS and the lower standard of 0.01 lb/mmBtu will present a compounded challenge if finalized as proposed. Commenters indicated that the difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate CEMS, and the difficulty in using CEMS will be exacerbated by the dramatically lower standard.[44] In particular, serious concerns remain with respect to whether a fPM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a CEMS to differentiate compliance from a false reading.[45] EPA attempts to allay these fears by claiming existing units can simply follow in the footsteps of new units, since new units have been subject to a CEMS requirement with a fPM emission limit of 0.090 lb/megawatt-hour since the inception of MATS.[46] **But that assurance provides no comfort—there are no new units.[47]**

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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

Power Plant Economic Impacts

The economic impacts for a lignite power plant from the Mercury and Air Toxics Standards (MATS) finalized rule can be substantial. The updated MATS rule, if implemented by the

[42] *PM Incremental Improvement Memo*, Doc. ID EPA-HQ-OAR-2018-0794-5836 (March 2023) ("Improvements to existing particulate control devices will be dependent on a range of factors including the design and current operation of the units, which is not documented in public forums. … Unfortunately, the details of how those units' ESP designs, upgrades, and operation are not publicly available …. In order to evaluate the applicability of one or more of these potential improvements, information would need to be known about the existing ESPs and their respective operation which is not documented in public forums.").

[43] *See, e.g., Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan,* 82 Fed. Reg. 32,294, 32,298 (July 13, 2017) ("Entergy's DSI and scrubber cost calculations were based on a propriety [sic] database, so we were unable to verify any of the company's costs. … Because of these issues, we developed our own control cost analyses ….").

[44] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[45] *Id.*

[46] 88 Fed. Reg. at 24874. The electrical output-based limit for new EGUs translates to approximately 0.009 lb/mmBtu, which is slightly below EPA's proposed limit of 0.010 lb/mmBtu.

[47] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

Environmental Protection Agency (EPA), aims to reduce mercury and other hazardous air pollutant emissions from coal-fired power plants. Coal-firing power plants, and lignite-firing power plants in particular, may face specific challenges and economic consequences in complying with these regulations, which could result in their forced retirement. Some potential economic impacts include:

1. **Escalating Operational Expenditures:** Under this rule, lignite power plants will face an excessive economic burden from a significant uptick in operational costs due to the integration of pollution control equipment. The installation of advanced technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates continuous monitoring and maintenance to ensure optimal performance. Design specifications vary from plant to plant which increases the complexities of the operating systems that require regular cleaning, replacement of consumables, and calibration, all of which incur additional expenses. Moreover, the implementation of pollution control, measures may necessitate alterations in combustion processes or the introduction of supplementary fuel, further driving up operational costs. As a result, lignite power plants are burdened with substantial ongoing expenditures, while also lacking a positive cost benefit analysis, which will undermine their economic viability and competitiveness in the energy market.

2. **Dilemma of Plant Retrofitting or Retirement:** Lignite power plants are confronted with the challenging prospect of either retrofitting existing facilities or contemplating retirement in response to the stringent requirements of the Mercury and Air Toxics Standards (MATS). Plant retrofitting involves substantial investment in upgrading equipment and implementing advanced pollution control technologies to achieve compliance with regulatory mandates. However, these retrofitting endeavors entail significant additional costs, potentially straining the financial resources of plant owners and operators. Moreover, the uncertainty surrounding the long-term economic viability of retrofitted plants further complicates decision-making processes.

3. **Impact on Electricity Prices:** The implementation of pollution control technologies to comply with MATS regulations can impose significant financial burdens on lignite power plants. These costs, encompassing the installation, maintenance, and operation of such technologies, would ultimately be transferred to consumers in the form of higher electricity prices. As power plants seek to recoup the expenses incurred in meeting regulatory requirements, consumers will experience an uptick in their electricity bills. This escalation in electricity prices will have far-reaching implications for households, businesses, and industries reliant on affordable energy. It will affect household budgets, impact the competitiveness of businesses, and influence consumer spending patterns. Additionally, higher electricity prices will introduce challenges for industries sensitive to energy costs, potentially leading to shifts in production, investment, and employment patterns within the broader economy. Therefore, the economic impact of elevated electricity prices resulting

from MATS compliance should be carefully considered within the context of the energy market, taking into account the implications for consumers, businesses, and overall economic growth.

4. **Employment Effects:** The escalation in costs and the possibility of plant retrofitting or retirement can reverberate through the lignite industry and associated sectors, potentially leading to job losses. As lignite power plants grapple with increased operational expenses and the financial strain of compliance with regulatory requirements, they may be compelled to streamline operations or even cease production altogether. Such decisions can have a ripple effect on employment within the community, impacting not only plant workers but also individuals employed in ancillary industries such as mining, transportation, and manufacturing. Job losses in these sectors can contribute to economic challenges, including reduced consumer spending, increased unemployment rates, and a decline in overall economic activity. Furthermore, the social and psychological impacts of job loss on affected individuals and communities cannot be understated, as they may face financial insecurity, stress, and uncertainty about their future prospects. Therefore, the potential job impacts stemming from increased costs and plant adjustments underscore the broader economic implications of regulatory compliance measures in the lignite industry.

5. **Regional Economic Consequences:** Lignite power plants are often linchpins of regional economies, exerting substantial influence on employment, tax revenue, and economic activity. Any shifts in the economic viability of these plants, whether due to increased costs, regulatory compliance burdens, or operational adjustments, will trigger broader consequences for local economies. The potential closure or downsizing of lignite power plants can result in the loss of direct and indirect employment opportunities, affecting not only plant workers but also individuals and businesses reliant on plant-related activities. Moreover, the decline in plant operations will lead to reduced tax revenue for local governments, impacting their ability to fund essential services and infrastructure projects. Additionally, the loss of economic activity associated with lignite power plants will ripple through the supply chain, affecting suppliers, vendors, and service providers in the region. This domino effect will exacerbate economic challenges, including decreased consumer spending, increased business closures, and a general downturn in economic vitality. Therefore, changes in the economic landscape of the lignite industry will have far-reaching consequences for regional economies, underscoring the interconnectedness between energy production, employment, and overall economic well-being at the local level.

6. **Impact on Investment Decisions:** The economic ramifications of the MATS rule can significantly shape investment decisions within the lignite industry. Plant owners and prospective investors must carefully evaluate the long-term economic feasibility and potential returns on investment in light of stringent regulatory compliance mandates. The substantial costs associated with MATS compliance, including technology upgrades and operational adjustments, may deter investment in lignite power plants or prompt

divestment from existing assets. Investors may reassess the risk-return profile of lignite-related ventures, considering factors such as regulatory uncertainty, market volatility, and shifting energy trends. Moreover, the potential for increased operational costs and regulatory burdens may incentivize investment in alternative energy sources or cleaner technologies, which align more closely with evolving environmental and sustainability objectives. Therefore, the economic implications of the MATS rule play a pivotal role in shaping investment decisions within the lignite industry, influencing capital allocation, project planning, and strategic resource allocation strategies.

7. **Legal and Regulatory Costs:** Meeting MATS requirements often entails significant legal and regulatory costs associated with monitoring, reporting, and ensuring continued compliance. Lignite power plants must allocate resources to navigate complex regulatory frameworks, engage legal counsel, and implement robust monitoring and reporting systems to adhere to emissions standards. These additional expenses contribute to the overall economic strain on lignite power plants, exacerbating the financial challenges associated with regulatory compliance. As a result, the burden of legal and regulatory costs further underscores the financial pressures faced by lignite power plant operators, shaping their strategic decision-making and resource allocation efforts.

Grid Reliability Impacts

Compliance with the Mercury and Air Toxics Standards (MATS) rule will likely have grid reliability impacts on regional power grids that rely on lignite- or other coal-firing power plants. The impacts on grid reliability for power grids that rely on lignite- or other coal-firing power plants can include:

1. **Operational Adaptations and Flexibility Constraints**: The implementation of pollution control technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates operational modifications within lignite power plants. These adjustments may include alterations to combustion processes, fuel handling procedures, and overall plant operations to accommodate the integration of new equipment and systems. However, such operational changes can compromise the inherent flexibility of lignite power plants to respond effectively to fluctuating load conditions and grid demands. The need for continuous operation of pollution control systems, coupled with potential limitations in responsiveness, may impede the plant's ability to ramp up or down quickly in response to changes in electricity demand or supply. Consequently, the reliability of lignite power plants to maintain grid stability and meet grid operator requirements may be compromised, raising concerns about their ability to ensure consistent and secure electricity supply. Thus, while MATS compliance aims to mitigate environmental impacts, the operational adaptations required may introduce challenges to the reliability and flexibility of lignite power plants in supporting a resilient and dynamic energy grid.

2. **Disruptions Due to Equipment Installation**: The installation and retrofitting of pollution control equipment often necessitate temporary shutdowns or reduced operating capacities within lignite power plants. These planned downtime periods are essential for integrating new equipment, conducting modifications, and ensuring compliance with regulatory requirements. However, the interruptions in plant operations during these installation phases will have adverse effects on the overall reliability and availability of the plant. The temporary cessation of power generation activities will disrupt electricity supply, potentially affecting grid stability and reliability. Moreover, extended downtime periods may lead to revenue losses for plant operators and suppliers, as well as inconvenience for consumers and end-users reliant on consistent electricity provision. Therefore, while essential for achieving compliance with MATS regulations, the equipment installation process poses challenges to the reliability and continuity of lignite power plant operations, emphasizing the importance of efficient planning and management to minimize disruptions.

3. **Efficiency Implications**: The introduction of pollution control technologies, especially those targeting mercury emissions reduction, will potentially undermine the overall efficiency of lignite power plants. While these technologies play a crucial role in meeting regulatory standards, they often require additional energy inputs and introduce operational complexities that can compromise plant efficiency. For instance, activated carbon injection (ACI) systems necessitate the injection of powdered carbon into the flue gas stream, which can increase resistance and pressure drops within the system, thus reducing overall efficiency. Similarly, flue gas desulfurization (FGD) systems require energy-intensive processes such as limestone slurry preparation and circulation, further impacting plant efficiency. The reduction in efficiency can translate to decreased electricity output per unit of fuel input, potentially affecting the plant's ability to generate electricity reliably and meet demand fluctuations. Consequently, while pollution control measures are essential for environmental protection, the associated efficiency implications underscore the need for careful optimization and balancing of environmental and operational considerations to ensure reliable power generation from lignite plants.

4. **Elevated Maintenance Demands**: The incorporation of MATS-compliant equipment, including ACI and FGD systems, often translates to heightened maintenance requirements within lignite power plants. The intricate nature of these pollution control technologies necessitates more frequent inspections, cleaning, and servicing to ensure optimal performance and regulatory compliance. However, the increased maintenance needs can result in extended periods of downtime, during which the plant may be unable to generate electricity, impacting its reliability and availability. Moreover, the allocation of resources and manpower to address maintenance tasks diverts attention and resources away from other operational activities, potentially affecting overall plant efficiency and productivity. Therefore, while essential for environmental compliance, the elevated maintenance

demands associated with MATS-compliant equipment pose challenges to the reliability and operational continuity of lignite power plants, highlighting the importance of proactive maintenance planning and execution to minimize disruptions.

5. **Inherent Fuel Supply Hurdles:** Lignite power plants grapple with inherent challenges associated with the utilization of lignite coal, particularly in meeting stringent emission standards. Lignite, characterized by its lower rank and elevated moisture content, poses unique obstacles in combustion processes. The variability in chemical composition across different seams of coal extracted from mines further complicates the task of ensuring consistent and efficient combustion. Each seam presents distinct combustion characteristics, necessitating meticulous adjustments in operational parameters to maintain compliance with emission regulations. Consequently, lignite power plants encounter difficulties in securing a reliable and uniform fuel supply, which undermines their ability to consistently meet emission targets and operational efficiency goals. The intricacies of managing diverse coal qualities exacerbate the complexities of pollution control measures, posing significant operational challenges for lignite power plants.

6. **Integration Challenges**: The introduction of new pollution control technologies into operational lignite power plants may encounter compatibility hurdles. Ensuring seamless integration with existing infrastructure is paramount for preserving reliability. Compatibility issues can emerge from differences in technology specifications, operational parameters, or control systems between the new equipment and the plant's established infrastructure. Unaddressed disparities may lead to operational inefficiencies, malfunctions, or system failures. Thus, meticulous planning and coordination are vital to mitigate compatibility risks and uphold the reliability of lignite power plants. Failure to address these challenges will compromise plant performance, emphasizing the need for thorough assessment and integration procedures when adopting new technologies.

7. **System Coordination and Grid Stability:** Adjustments in operating conditions and responses to fluctuating load demands can disrupt system coordination and compromise grid stability. Lignite power plants must coordinate closely with grid operators to maintain reliable electricity supply while adhering to MATS requirements. Changes in plant operations, such as implementing pollution control technologies or adjusting output levels, can affect the overall balance of supply and demand within the grid. Without effective coordination, these changes may lead to imbalances, voltage fluctuations, or frequency deviations, posing risks to grid stability. Therefore, robust communication and collaboration between lignite power plants and grid operators are essential to ensure seamless integration of plant operations with broader grid dynamics. By coordinating effectively, lignite power plants can contribute to grid stability while meeting regulatory obligations, ensuring the reliable delivery of electricity to consumers.

8. **Continuous Compliance Management**: Adhering to emission limits mandated by MATS necessitates ongoing monitoring and fine-tuning of pollution control equipment. The chemical properties of lignite can vary even within coal seams from the same mine, posing challenges in preparation and adjustment for plant operations. This variability complicates efforts to maintain consistent compliance, requiring dynamic adjustments in day-to-day plant operations. Consequently, ensuring reliable compliance becomes a dynamic process, demanding meticulous attention to detail and proactive management of pollution control systems. Consistent monitoring and adjustment are essential to mitigate emissions effectively while sustaining the operational reliability of lignite power plants amidst the inherent variability of lignite coal properties.

9. **Supply Chain Vulnerabilities:** The consolidation in the power plant equipment sector over the past decade has reduced the number of suppliers available. Relying on specific suppliers for pollution control equipment and technologies introduces supply chain risks. Disruptions in the supply chain, such as shortages, delays, or quality issues, will impede the timely installation and operation of essential equipment, jeopardizing reliability. Lignite power plants must carefully assess and manage these supply chain vulnerabilities to ensure uninterrupted access to critical components and technologies necessary for regulatory compliance and operational integrity. Proactive measures, such as diversifying suppliers or implementing contingency plans, are crucial for mitigating supply chain risks and maintaining the reliability of lignite power plants.

10. **Long-Term Viability and Aging Infrastructure:** Compliance with MATS regulations will raise concerns about the long-term viability of older lignite power plants. Aging infrastructure may struggle to adapt to the requirements of new pollution control technologies, posing challenges that will impact reliability. The integration of these technologies into outdated systems may require extensive retrofitting or upgrades, which can strain resources and prolong downtime. Moreover, the operational lifespan of aging infrastructure may be limited, leading to questions about the economic feasibility of investing in costly compliance measures. Plant owners must carefully assess the cost-benefit ratio of compliance efforts and consider the potential impact on reliability when evaluating the long-term viability of older lignite power plants. Failure to address these challenges will compromise the reliability and competitiveness of these facilities in the evolving energy landscape.

Section D: Modeling Results

Summary

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case, instead it conducted a Resource Adequacy and reserve margin analysis, which EPA has claimed is necessary but not sufficient to grid reliability.[48]

EPA's lack of reliability modeling prompted several entities to voice concerns in the original docket for the Proposed MATS rule would negatively impact grid reliability, including the National Rural Electric Coop Association, the American Coal Council, The Lignite Energy Council, PGen, the American Public Power Association, and the National Mining Association.[49,50,51,52,53,54]

To provide this necessary perspective, Center of the American Experiment modeled the reliability and cost impacts of the proposed Mercury and Air Toxics Standards (MATS) in the subregions consisting of the Midcontinent Independent Systems Operator (MISO) as it relates to the elimination of the subcategory for lignite-fired power plants.[55,]

Our analysis determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system if these resources are replaced with wind, solar, battery storage, and natural gas plants consistent with the EPA's estimates for capacity values for intermittent and thermal resources.

Building these replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost \$12.93 billion, \$14.88 billion, and \$16.76 billion, respectively, from 2024 through 2035, resulting in incremental costs of \$1.9 billion in the Partial

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[48] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.

[49] NRECA Comments, EPA-HQ-OAR-2018-0794-5956, at 5-6.

[50] American Coal Council Comments, EPA-HQ-OAR-2018-0794-6808, at 3.

[51] LEC Comments, EPA-HQ-OAR-2018-0794-5957, at 17.

[52] PGen Comments, EPA-HQ-OAR-2018-0794-5994, at 5.

[53] APPA Comments, EPA-HQ-OAR-2018-0794-5958, at 33.

[54] NMA Comments, EPA-HQ-OAR-2018-0794-5986, at 29.

[55] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.

scenario and $3.8 billion in the Full scenario through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts, which can result in food spoilage, property damage, lost labor productivity, and loss of life. American Experiment calculated the economic damages associated with the increase in unserved electricity demand using a metric called the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Our analysis found that the MATS rule would cause an additional 73,699 additional megawatt hours (MWh) of unserved load in the in the Full MATS Retirement scenario in 2035 using 2019 hourly electricity demand and wind and solar capacity factors. Using a conservative value for the VoLL of $14,250 per MWh, we conclude the MATS rule would produce economic damages of $1.05 billion under these conditions.

Therefore, the incremental costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO under the Full scenario exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.

Modeling the Reliability and Cost of the MISO Generating Fleet Under Three Scenarios

Our analysis examined the impact of the proposed MATS rules on the reliability of the MISO system through 2035 by comparing two lignite retirement scenarios to a “Status Quo” scenario that represents “business as usual” that assumes no changes to the generating fleet occur due to the MATS rule, or any other of EPA’s pending regulations.[56]

Status Quo scenario: Installed generator capacity assumptions for MISO in the Status Quo scenario are based on announced retirements from U.S. Energy Information Administration (EIA) database and utility Integrated Resource Plans (IRPs) through 2035 compiled by Energy Ventures Analysis on behalf America’s Power, a trade association whose sole mission is to advocate at the federal and state levels on behalf of the U.S. coal fleet.[57] This database is also used by the NERC LTRA suggesting it is among the most credible databases available for this analysis.[58] It should be noted that this database leaves considerably more coal and natural gas on its system than the MISO grid EPA assumes will be in service in the coming years in its Proposed Rule Supply Resource

[56] See Appendix 2: Capacity Retirements and Additions in Each Scenario.
[57] America’s Power, “Proprietary data base maintained by Energy Ventures Analysis, an energy consultancy with expertise in electric power, natural gas, oil, coal, renewable energy, and environmental policies” Personal Communication, November 3, 2023.
[58] North American Electric Reliability Corporation, “2023 Long-Term Reliability Assessment,” December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Utilization file, meaning our reliability assessment will be more conservative than if we used EPA's capacity projections.

Retired thermal resources in the Status Quo scenario are replaced by solar, wind, battery storage, and natural gas in accordance with the current MISO interconnection queue to maintain resource adequacy based on capacity values given to these generators in EPA's Proposed Rule Supply Resource Utilization file.[59] These capacity values are described in greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.

Partial MATS Retirement scenario: The Partial MATS retirement scenario assumes 1,150 megawatts (MW) of lignite fired capacity in North Dakota is retired in addition to incorporating all of the announced retirements in the Status Quo. This value was chosen because it represents the retirement of one lignite facility in North Dakota that serves the MISO market. These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[60]

Full MATS scenario: The Full MATS retirement scenario assumes the MATS regulations will cause all 2,264 MW of lignite-fired generators in the MISO system to retire, in addition to incorporating the retirements in the Status Quo scenario will occur.[61] These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[62]

Reliability in each scenario

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case. Instead, it conducted a Resource Adequacy analysis of its proposed rule, compared to the Post IRA base case.

Resource Adequacy and reserve margin analyses can be useful tools for determining resource adequacy and reliability, but the shift away from dispatchable thermal resources (fossil fuel) toward intermittent resources (wind and solar) increases the complexity and uncertainty in these analyses and makes them increasingly dependent on the quality of the assumptions used to construct capacity accreditations.[63]

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[59] U.S. Environmental Protect Agency, "Proposed Regulatory Option," Zip File, https://www.epa.gov/system/files/other-files/2023-04/Proposed%20Regulatory%20Option.zip
[60] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[61] These figures represent the rated summer capacity as indicated by the U.S. Energy Information Administration.
[62] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[63] See Appendix 4: Resource Adequacy in Each Scenario.

This is likely a key reason why EPA has distinguished between resource *adequacy* and resource *reliability* in its Resource Adequacy Technical Support Document for its proposed carbon dioxide regulations on new and existing power plants.[64,65] EPA stated:

> "As used here, the term **resource adequacy** is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while **reliability** includes the ability to deliver the resources to the loads, such that the overall power grid remains stable." **[emphasis added].**" EPA goes on to say that "resource adequacy … is necessary (but not sufficient) for grid reliability.[66]

As the grid becomes more reliant upon non-dispatchable generators with lower reliability values, it is crucial to "stress test" the reliability outcomes of systems that use the EPA's capacity value assumptions in their Resource Adequacy analyses by comparing historic hourly electricity demand and wind and solar capacity factors against installed capacity assumptions in the Status Quo, Partial, and Full scenarios.

We conducted such an analysis by comparing EPA's modeled MISO generation portfolio to the historic hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, and 2022. These data were obtained from the U.S. Energy Information Administration (EIA) Hourly Grid Monitor to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).[67]

For our analysis, hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions. These assumptions are generous to the EPA because they increase the annual output of wind and solar generators to levels that are not generally observed in MISO.

Extent of the Capacity Shortfalls

While our modeling determined that the retirement of lignite facilities had a minimal impact on the number of hours of capacity shortfalls observed in the Partial and Full scenarios, retiring the lignite facilities makes the extent of capacity shortfalls worse.

[64] EPA did not produce a Resource Adequacy Technical Support Document for the MATS rules.
[65] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.
[66] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[67] U.S. Energy Information Administration, "Hourly Grid Monitor," https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

For example, Figure D-1 shows largest capacity shortfalls in the Status Quo scenario, which occur in 2035 using the 2021 Historical Comparison Year for hourly electricity demand and wind and solar capacity factors.

Each resource's hourly performance is charted in the graph below. Thermal units are assumed to be 100 percent available, which is consistent with EPA's capacity accreditation for these resources, and wind and solar are dispatched as available based on 2021 fluctuations in generation. Blue sections reflect the use of "Load Modifying Resources," which are reductions in electricity consumption by participants in the MISO market.

Purple areas show time periods where the batteries are discharged. These batteries are recharged on January 8th and 9th using the available natural gas and oil-fired generators. Red areas represent periods where all of the resources on the grid are unable to serve load due to low wind and solar output and drained battery storage systems. At its peak, the largest capacity shortfall is 15,731 MW.

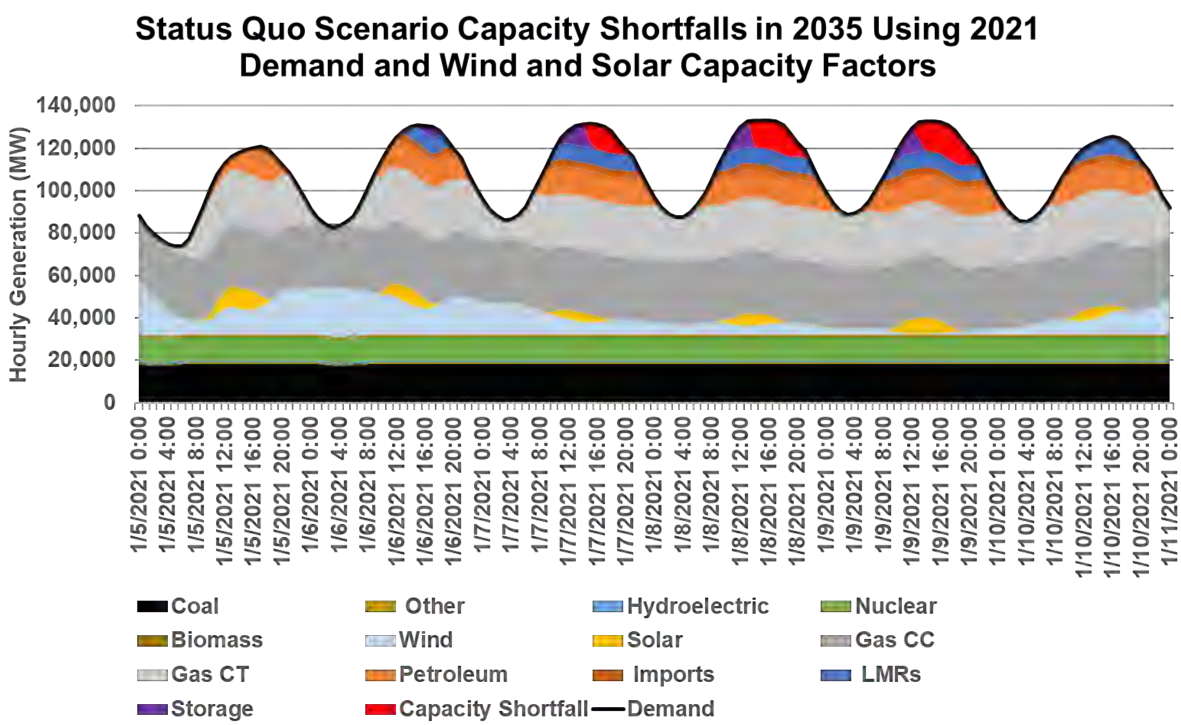

Figure D-1. This figure shows the generation of resources on the MISO grid in the Status Quo during a theoretical week in 2035. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage does not last long enough to avoid blackouts during a wind drought.

These capacity shortfalls become more pronounced in the Partial and Full scenarios as less dispatchable capacity exists on the grid to serve load. Figure D-2 shows the three capacity shortfall events in Figure D-1. It depicts the blackouts observed in the Status Quo scenario in green, and the additional MW of unserved load in the Partial and Full scenarios in yellow and red, respectively.

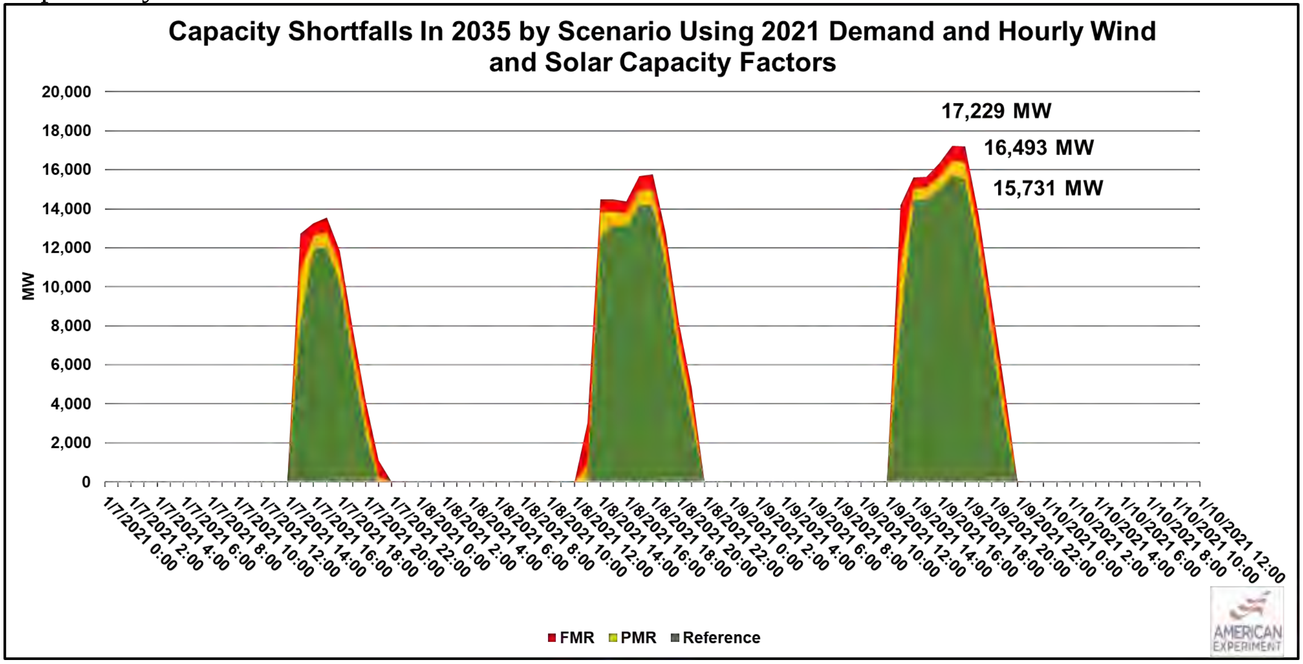

Figure D-2. Capacity shortfalls increase during a hypothetical January 9th, 2035 from 15,731 MW at their peak in the Status Quo to 16,493 MW in the Partial scenario and 17,229 MW in the Full scenario.

Table D-1 shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfall due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

The largest incremental increase in capacity shortfalls would occur in the 2020 HCY in the Full scenario as the blackouts would increase from 552 MW in the Status Quo scenario to 3,295 in the Full scenario, a difference of 2,743 MW.

Maximum MW Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	15,130	15,842	712	16,530	1,400
2020	552	2,587	2,034	3,295	2,743
2021	15,731	16,493	762	17,229	1,498
2022	10,615	11,409	794	12,177	1,562

Table D-1. This table shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfalls due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

It is important to note that this difference is larger than the amount of lignite-fired capacity that is retired in the Full scenario (2,264 MW) because the retirement of these facilities reduces the amount of capacity available to charge battery storage resources.

Unserved MWh in Each Scenario

The amount of unserved load in each scenario can also be measured in megawatt hours (MWh). This metric is a product of the number of hours with insufficient energy resources multiplied by the hourly energy shortfall, measured in MW. This metric may be a more tangible way to understand the impact that the unserved load will have on families, businesses, and the broader economy. Each MWh reflects an increment of time where electric consumers in the MISO grid will not have access to power.

Table D-2 shows the number of MWhs of unserved load in each scenario for the four HCYs studied. In some HCYs, the incremental number of unserved MWhs is fairly small, but in other years they are substantial. In the 2020 HCY, the Partial scenario had 2,042 more MWhs of unserved load than the Status Quo scenario, and the Full scenario had 4,265 MWh of additional unserved load, compared to the Status Quo Scenario.

Total MWh Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	168,723	204,050	35,327	242,393	73,669
2020	582	2,624	2,042	4,847	4,265
2021	244,743	273,927	29,184	304,021	59,278
2022	53,458	62,223	8,765	71,304	17,846

Table D-2. The incremental MWh of unserved load ranges from 2,042 to 35,327 in the Partial scenario, and from 4,265 to 73,669 in the Full scenario.

In the 2019 HCY, the Partial scenario experienced an additional 35,327 MWh of unserved load and the Full scenario experienced 73,669 MWh of unserved load. These additional MWh of unserved load will impose hardships on families, businesses, and the broader economy.

The Social Cost of Blackouts Using the Value of Lost Load (VoLL)

Blackouts are costly. They frequently result in food spoilage, lost economic activity, and they can also be deadly. Regional grid planners attempt to quantify the cost of blackouts with a metric called the Value of Lost Load (VoLL). The VoLL is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

MISO currently assigns a Value of Lost Load (VOLL) of $3,500 per megawatt hour of unserved load. However, Potomac Economics, the Independent Market Monitor for MISO, recommended a value of $25,000 per MWh for the region.[68] For this study, we used a midpoint value of $14,250 per MWh of unserved load to calculate the social cost of the blackouts under each modeled scenario.

Table D-3 shows the economic damage of blackouts in each scenario in model year 2035 and shows the incremental increase in the VOLL in the Partial and Full scenarios. Incremental VOLL costs are highest using the 2019 HCY where MISO experiences an additional $503.4 million in economic damages due to blackouts in the Partial scenario, and an additional $1.05 billion in the Full scenario.

Value of Lost Load for Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	$2,404,309,657	$2,907,716,665	$503,407,008	$3,454,098,692	$1,049,789,035
2020	$8,296,505	$37,389,117	$29,092,612	$69,074,216	$60,777,712
2021	$3,487,594,170	$3,903,464,847	$415,870,677	$4,332,301,464	$844,707,294
2022	$761,782,023	$886,680,023	$124,898,001	$1,016,083,680	$254,301,657

Table D-3. MISO would experience millions of dollars in additional economic damage if the lignite fired power plants in its footprint are shut down in response to the MATS regulations.

It is important to note that these VOLL figures are not the total estimated cost impacts of blackouts for the MATS regulations. Rather, they are a snapshot of a range of possible outcomes for the year 2035 based on variations in electricity demand and wind and solar productivity.

The VOLL demonstrates harm of the economy in a multitude of ways. For the industrial/commercial sector, direct costs from losing power (and therefore benefits from avoiding power outages) can be (1) opportunity cost of idle resources, (2) production shortfalls / delays, (3) damage to equipment and capital, and (4) any health or safety impacts to employees. There are also indirect or macroeconomic costs to downstream businesses/consumers who might depend on the products from a company who experiences a power outage.[69]

For the residential sector, the direct costs are different. They can include (1) restrictions on activities (e.g. lost leisure time, lost work time, and associated stress), (2) financial costs through property damage (e.g. damage to real estate via bursting pipes, food spoilage), and (3) health and safety issues (e.g. reliance on breathing machines, air filters).[70]

[68] David B. Patton, "Summary of the 2022 MISO State of the Market Report," Potomac Economics, July 13, 2023, https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf.
[69] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.
[70] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

Hours of Capacity Shortfalls

Comparing hourly historic electricity demand and wind and solar output to MISO grid in the Status Quo scenario, our modeling found that MISO would have capacity shortfalls in the 2019, 2021, and 2022 HCYs which can be seen in Table D-4 below.

There would be additional capacity shortfalls in all of the HCYs modeled in the Partial and Full scenarios, where the Partial scenario would experience four additional hours of blackouts in 2019 HCY, one additional hour of blackouts in the 2020 HCY, four additional hours of blackouts in 2021 HCY, and one additional hour of blackouts in the 2022 HCY. In the Full scenario, there would be five additional hours of blackouts in the 2019 HCY, one additional hour of blackouts in the 2020 HCY, eight additional hours in the 2021 HCY, and two additional hours in the 2022 HCY, compared to the Status Quo Scenario.

Hours of Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	28	32	4	33	5
2020	2	3	1	3	1
2021	24	28	4	32	8
2022	13	14	1	15	2

Table D-4. Capacity shortfalls occur in three of the four HCYs in the Status Quo scenario and all four HCYs for the Partial and Full scenarios.

Cost of replacement generation

Our VOLL analysis demonstrates that the MATS rules will cause significant economic harm in MISO by reducing the amount of dispatchable capacity on the grid due to lignite plant closures stemming from the removal of the lignite subcategory.

However, load serving entities (LSEs) will also begin to incur costs as they build replacement generation to maintain resource adequacy if lignite resources are forced to retire in response to the proposed MATS rules. These costs will be passed on to electricity consumers and must be calculated to produce accurate estimates of the true cost of the MATS regulations.

We modeled the cost of the replacement generation under the Status Quoe, Partial and Full scenarios. The cost of the Partial and Full scenarios, when compared to the Status Quo scenario, is used to determine the additional economic burden that the MATS regulations will impose onto MISO electricity customers.

Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035 (see Figure D-3).

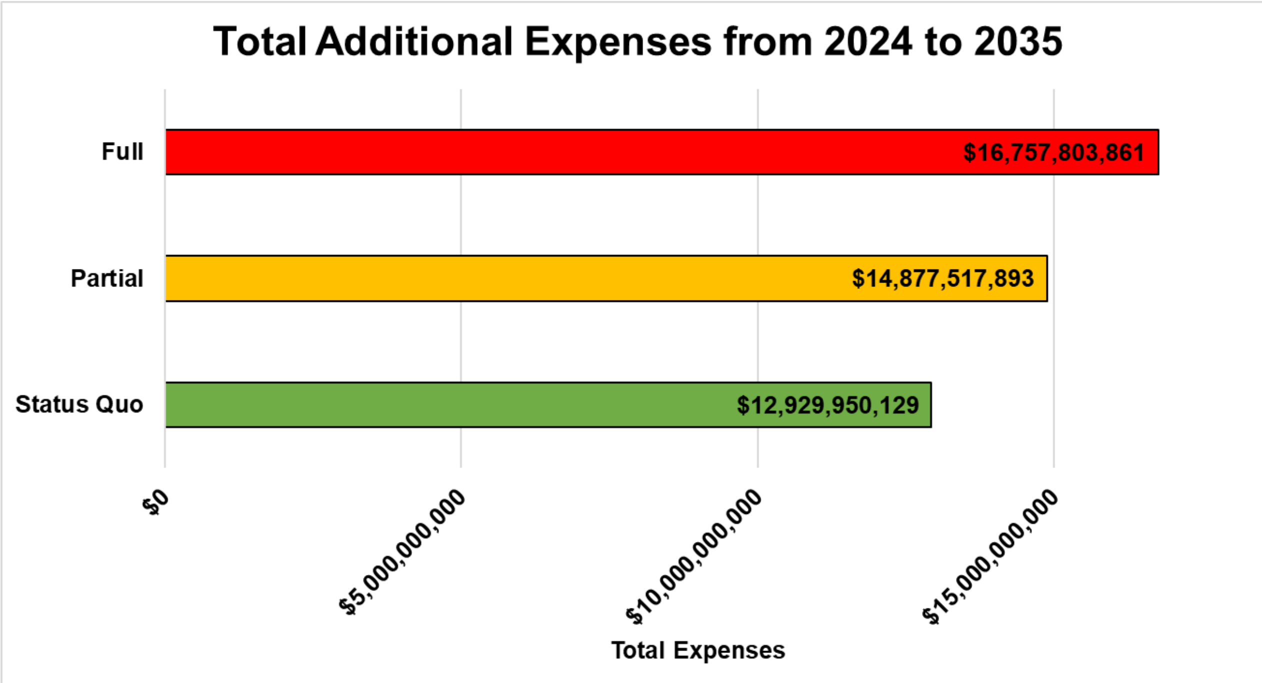

Figure D-3. The Partial scenario will cost $1.95 billion more than the Status Quo scenario from 2024 through 2035 and the Full scenario will cost $3.8 billion more than the Status Quo scenario in this timeframe.

Figure D-4 shows the incremental cost of the Partial and Full scenarios from 2024 through 2030, the period reflecting the up-front costs of complying with the regulations. From 2024 through 2028, LSEs would incur $337 million by building replacement generation in the Partial scenario, compared to the Status Quo scenario, and $654 million in the Full scenario, relative to the Status Quo. It should be noted that these costs are only the cost of building replacement generation and do not factor in the cost of decommissioning or remediating existing power plants or mine sites.

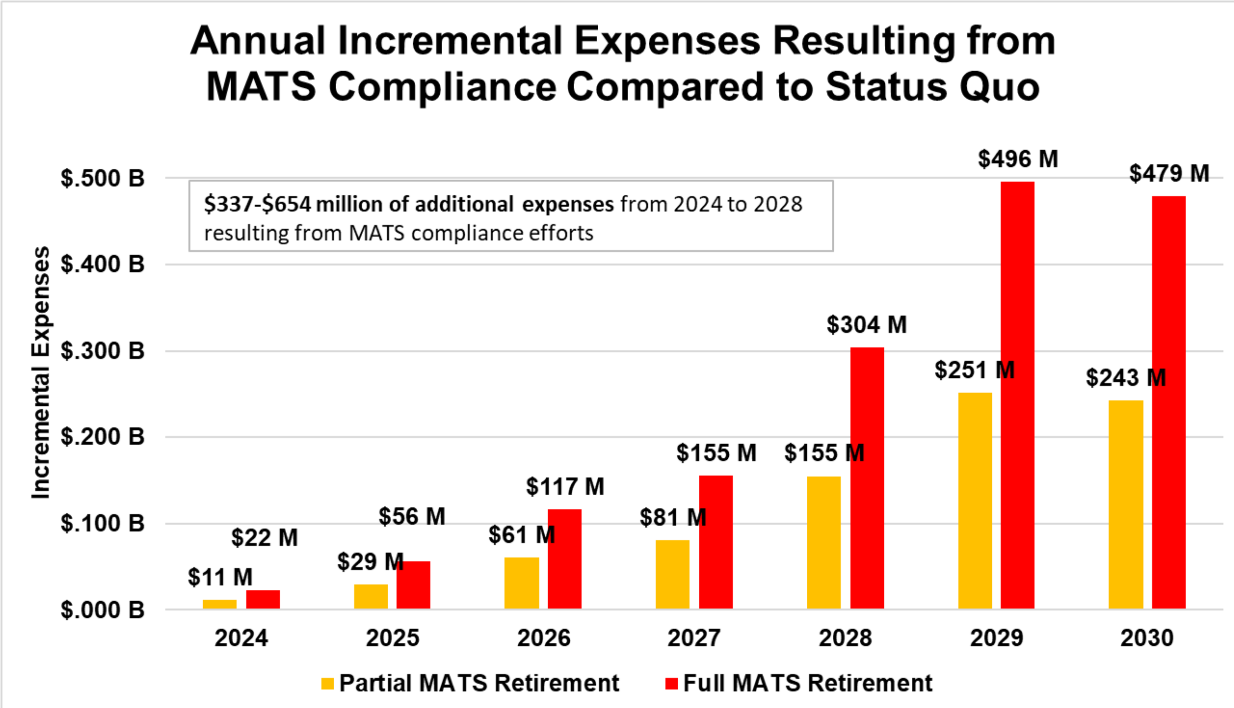

Figure D-4. This figure shows the annual cost of building the replacement capacity needed to maintain resource adequacy after the retirement of the lignite plants based on EPA's capacity accreditation values for wind, solar, storage, and thermal resources.

We describe the total costs of replacement generation capacity for each scenario in greater detail below. The assumptions used to calculate the cost of replacement generation can be found in Appendix 1: Modeling Assumptions.

Status Quo scenario:

The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. These retirements are already projected to occur without imposition of the new MATS Rule or other federal regulations. This retired capacity is replaced with 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.[71]

The total cost of replacement generation for the Status Quo scenario is $12.9 billion. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Status Quo scenario saves $32 billion in fuel costs, $11.5 billion in variable operations and maintenance costs, and $5 billion in taxes. However, these savings are

[71] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

far outweighed by $5.1 billion in additional fixed costs, $16 billion in capital costs, $2.1 billion in transmission costs, and $38.2 billion in utility profits (see Figure D-5).

Figure D-5. The Status Quo scenario saves consumers money from lower fuel costs, fewer variable operations and maintenance costs, and lower taxes (due to federal subsidies) but these savings are outweighed by the additional costs. As a result, building the grid in the Status Quo scenario would increase costs by $12.93 billion compared to today's costs.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.89 cents per kWh in the Status Quo scenario, an increase of nearly 3.5 percent relative to current costs of 9.56 cents per kWh.[72]

Partial MATS Retirement scenario:

The Partial scenario results in the closure of 1,151 MW of lignite capacity and necessitates an incremental increase in replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage, compared to the Status Quo scenario.[73]

The total cost of replacement generation for the Partial scenario is $14.9 billion, and the total incremental cost is $1.9 billion compared to the Status Quo scenario. The majority of these

[72] Annual Electric Power Industry Report, Form EIA-861 detailed data files, https://www.eia.gov/electricity/data/eia861/.
[73] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Partial scenario saves $32.7 billion in fuel costs, $11.6 billion in variable operations and maintenance costs, and $5.1 billion in taxes. However, these savings are far outweighed by $5.3 billion in additional fixed costs, $17.1 billion in capital costs, $2.2 billion in transmission costs, and $39.7 billion in utility profits (see Figure D-6).

Figure D-6. The Partial scenario results in an $14.88 billion in additional costs compared to the current grid due to additional capital costs, fixed operations and maintenance costs, additional transmission costs, and additional utility profits.

Compared to the Status Quo scenario, the incremental savings are $664 million in fuel costs, $119.7 million in variable operations and maintenance costs, and $102.2 million in taxes, which are outweighed by $178.7 million in additional fixed costs, $1.1 billion in capital costs, $116.5 million in transmission costs, and $1.4 billion in utility profits (see Figure D-7).

Figure D-7. The Partial scenario will cost MISO ratepayers an additional $1.9 billion from 2024 through 2035.

These incremental costs mean Load Serving Entities will incur an additional $1.9 billion because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $337 million of additional expenses compared to the Status Quo scenario (see Figure D-8).

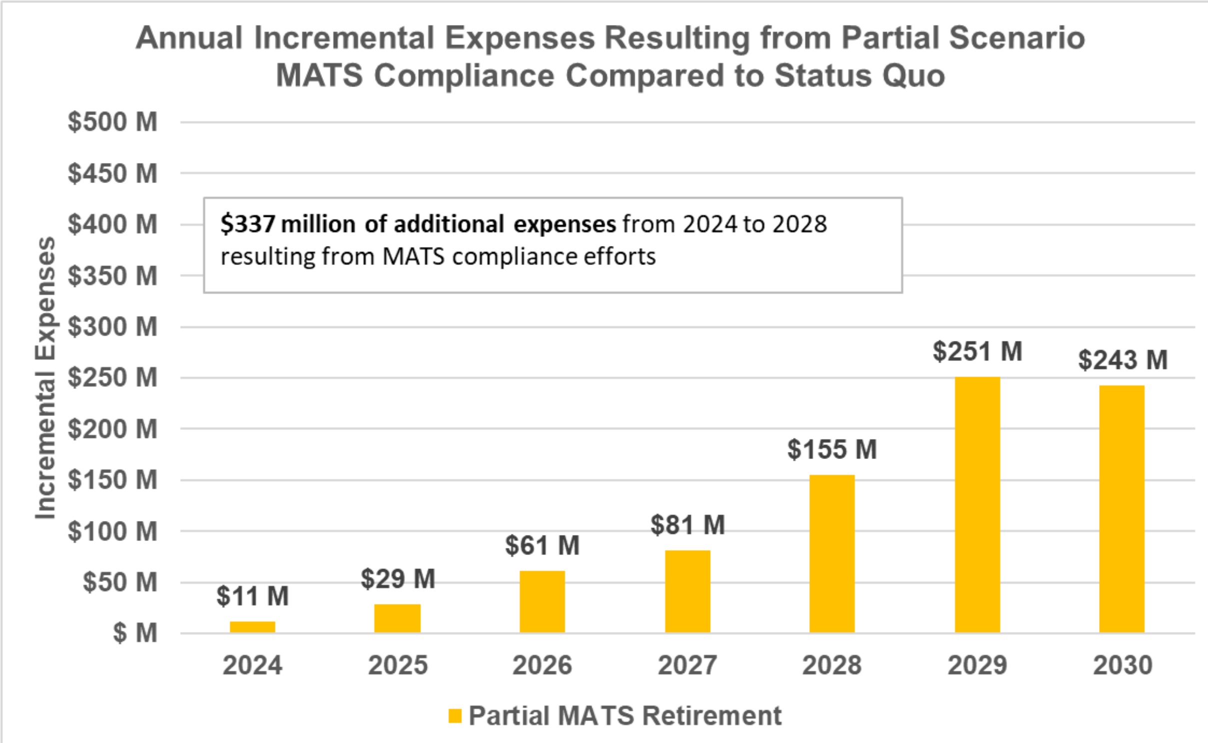

Figure D-8. This figure shows the annual incremental cost incurred by LSEs as a result of the lignite closures in the Partial scenario.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.95 cents per kWh in the Partial scenario, an increase of nearly 3.9 percent relative to current costs of 9.58.

Full MATS scenario:

Under the Full scenario, 2,264 MW of lignite capacity would be forced to retire resulting results in an incremental increase in replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage compared to the Status Quo scenario.

The total cost of replacement generation for the Full scenario is $16.8 billion, and the total incremental cost is $3.8 billion compared to Status Quo scenario. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Full scenario saves $33.3 billion in fuel costs, $11.7 billion in variable operations and maintenance costs, and $5.2 billion in taxes. However, these savings are far outweighed by $5.4 billion in additional fixed costs, $18.1 billion in capital costs, $2.4 billion in transmission costs, and $41.1 billion in utility profits (see Figure D-9).

Figure D-9. The Full scenario results in an increase of $16.76 billion in costs compared to the current grid.

Compared to the Status Quo scenario, the incremental savings are $1.3 million in fuel costs, $235.1 million in variable operations and maintenance costs, and $202 million in taxes, which are outweighed by $350.8 million in additional fixed costs, $2.1 billion in capital costs, $229.1 million in transmission costs, and $2.8 billion in utility profits (see Figure D-10).

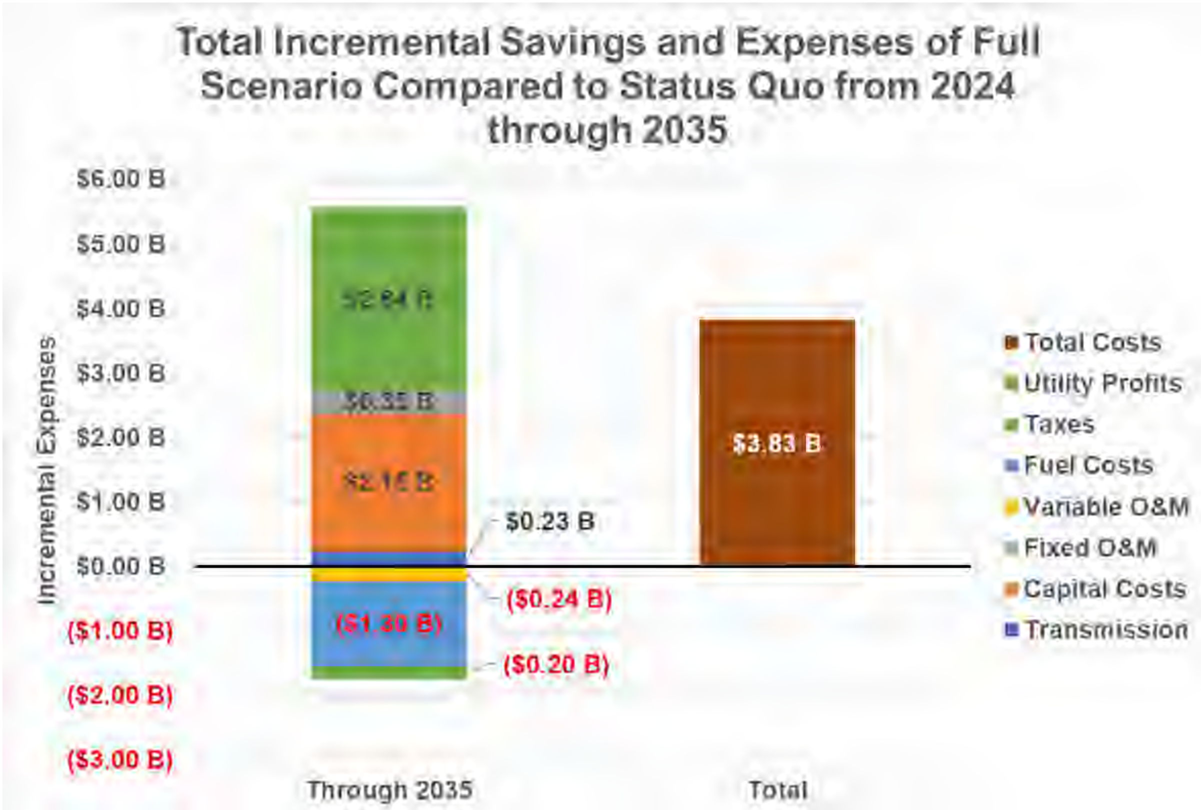

Figure D-10. This figure itemizes the expenses incurred in the Full scenario, which will cost an additional $3.8 billion compared to the Status Quo scenario.

These incremental costs mean Load Serving Entities will incur an additional $3.8 billion in the Full scenario because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $654 million of additional expenses compared to the Status Quo scenario (see Figure D-11).

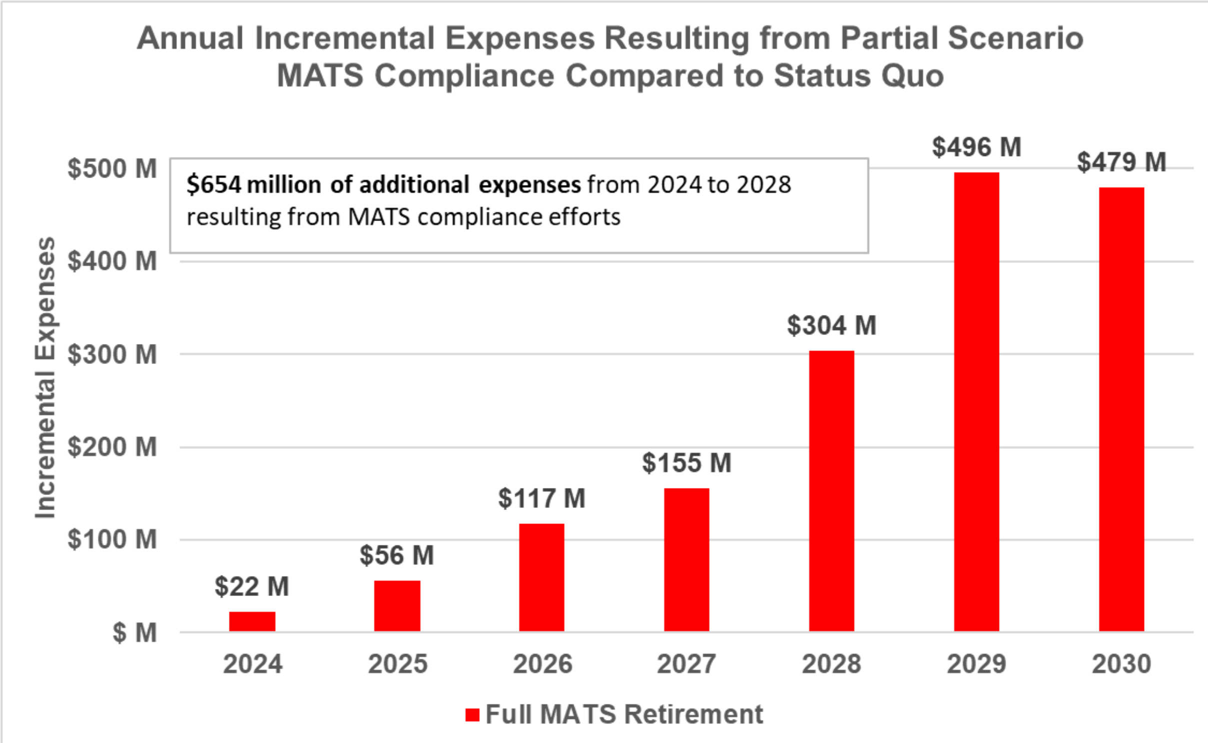

Figure D-11. LSEs would incur an additional $654 million in additional expenses, compared to the Status Quo scenario, as a result of the proposed MATS rules.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.97 cents per kWh in the Full scenario, an increase of nearly 4.1 percent relative to current costs of 9.58.

Conclusion:

By effectively eliminating the subcategory for lignite power plants and ignoring the breadth of evidence demonstrating that these regulations are not reasonably attainable, the MATS rules will increase the severity of capacity shortfalls in the MISO region, resulting in economic damages from the ensuing blackouts ranging from $29 million to $1.05 billion, depending on the HCY used, and imposing $1.9 billion to $3.8 billion in the cost of replacement generation capacity in the Partial and Full scenarios, respectively.

Therefore, the costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.[74]

[74] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.

Appendix 1: Modeling Assumptions

Electricity Consumption Assumptions

Annual electricity consumption in each model year is increased in accordance with EPA's assumptions in the IPM in each of the MISO subregions.

Peak Demand and Reserve Margin Assumptions

The modeled peak demand and reserve margin in each of the model years are increased in accordance with the IPM in each of the MISO subregions.

Time Horizon Studied

This analysis studies the impact of the proposed MATS rules from 2024 through 2035 to accurately account for the costs LSEs would incur by building replacement generation in response to the potential shutdown of lignite capacity.

This timeline downwardly biases the cost of compliance with the regulations because power plants are long term investments, often paid off over a 30-year time period. This means the changes to the resource portfolio in MISO resulting from these rules will affect electricity rates for decades beyond 2035.

Hourly Load, Capacity Factors, and Peak Demand Assumptions

Hourly load shapes and wind and solar generation were determined using data for the entire MISO region obtained from EIA's Hourly Grid Monitor. Load shapes were obtained for 2019, 2020, 2021, and 2022. [75] These inputs were entered into the model to assess hourly load shapes and assess possible capacity shortfalls in 2035 using each of the historical years.

Capacity factors used for wind and solar facilities were adjusted upward to match EPA assumptions that new wind and solar facilities will have capacity factors as high as 42.2 percent and 24.7 percent, respectively. These are generous assumptions because the current MISO-wide capacity factor of existing wind turbines is only 36 percent, and solar is 20 percent.

Our analysis upwardly adjusted observed capacity factors to EPA's estimates despite the fact that EPA's assumptions for onshore wind are significantly higher than observed capacity factors reported from Lawrence Berkeley National Labs, which demonstrates that new wind turbines entering operation since 2015 have never achieved annual capacity factors of 42.2 percent (See Figure D-12).[76]

[75] Energy Information Administration, "Hourly Electric Grid Monitor," Accessed August 12, 2022, https://www.eia.gov/ electricity/gridmonitor/dashboard/electric_overview/balancing_authority/MISO
[76] Lawrence Berkely National Labs, "Wind Power Performance," Land Based Wind Report, Accessed July 27, 2023, https://emp.lbl.gov/wind-power-performance.

Figure D-12. This *figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 42.2 percent capacity factor on an annual basis.*

Another generous assumption is that we did not hold natural gas plants accountable to other EPA rules, such as the Carbon Rule, that may be in effect in addition to the MATS rule and would cap natural gas generators at 49 percent capacity factors to avoid using carbon capture and sequestration or co-firing with hydrogen. Doing so would have resulted in even more capacity shortfalls.

Line Losses

Line losses are assumed to be 5 percent of the electricity transmitted and distributed in the United States based on U.S. on EIA data from 2017 through 2021.[77]

Value of Lost Load

The value of lost load (VoLL) is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

[77] Energy Information Administration, "How Much Electricity is Lost in Electricity Transmission and Distribution in the United States," Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

Our analysis uses a conservative midpoint estimate of $14,250 per MWh for VoLL. This value is higher than MISO's previous VoLL estimate of $3,500 per MWh, but significantly lower than the Independent Market Monitor's suggested estimate of $25,000 per MWh.[78]

Plant Retirement Schedules

Our modeling utilizes announced coal and natural gas retirement dates from U.S. EIA databases and announced closures in utility IRPs using a dataset collected by NERA economic consulting.

Plant Construction by Type

The resource adequacy and reliability portions of this analysis use MISO Interconnection Queue data to project into the future. EPA capacity values are applied to each newly constructed resource until the MISO system hits its target reserve margin based on EPA's peak demand forecast in its IPM.

Load Modifying Resources, Demand Response, and Imports

Our model allows for the use of 7,875 MW of Load Modifying Resources (LMRs) and 3,638 MW external resources (imports) in determining how much reliable capacity will be needed within MISO to meet peak electricity demand under the new MATS rules.

Utility Returns

Most of the load serving entities in MISO are vertically integrated utilities operating under the Cost-of-Service model. The amount of profit a utility makes on capital assets is called the Rate of Return (RoR) on the Rate Base. For the purposes of our study, the assumed rate of return is 9.9 percent with debt/equity split of 48.92/51.08 based on the rate of return and debt/equity split of the ten-largest investor-owned utilities in MISO.

Transmission

This analysis assumes the building of transmission estimated at $10.3 billion, which is consistent with MISO tranche 1 for the Status Quo Scenario. For the Full and Partial scenarios, transmission costs are estimated to be $223,913 per MW of new installed capacity to account for the increased wind, solar, storage, and natural gas capacity additions.

Taxes and Subsidies

Additional tax payments for utilities were calculated to be of 1.3 percent of the rate base. The state income tax rate of 7.3 percent was estimated by averaging the states within the MISO region. The

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[78] Potomac Economics, "2022 State of the Market Report for the MISO Electricity Markets," Independent Market Monitor for the Midcontinent ISO, June 15, 2023, https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

Federal income tax rate is 21 percent. The value of the Production Tax Credit (PTC) is $27.50. The Investment Tax Credit (ITC) 30 percent through 2032, 26 percent in 2033, and 22 percent in 2034.

Battery Storage

Battery storage assumes a 5 percent efficiency loss on both ends (charging and discharging).

Maximum discharge rates for the MISO system model runs were held at the max capacity of the storage fleet, less efficiency losses. Battery storage is assumed to be 4-hour storage, while pumped storage is assumed to be 8-hour storage.

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[79] However, our study does not take wind or solar degradation into account.

Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs for all new generating units are sourced from the EIA 2023 Assumptions to the Annual Energy Outlook (AOE) Electricity Market Module (EMM). These costs are held constant throughout the model run. Expenses for fixed and variable O&M for new resources were also obtained from the EMM. MISO region capital costs were used, and national fixed and variable O&M costs were obtained from Table 3 in the EMM report.[80]

Discount Rate

A discount rate of 3.76 percent is used in accordance with EPA's assumptions in the IPM.

Unit Lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account. Wind turbines are assumed to last for 20 years, solar panels are assumed to last 25 years, battery storage for 15 years. Natural gas plants are assumed to last for 30 years.

Repowering

Our model assumes wind turbines, solar panels, and battery storage facilities are repowered after they reach the end of their useful lives. Our model also excludes economic repowering, a growing

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[79] Liam Stoker, "Built Solar Assets Are 'Chronically Underperforming,' and Modules Degrading Faster than Expected, Research Finds," PV Tech, June 8, 2021, https://www.pv-tech.org/built-solar-assets-are-chronically-underperforming-andmodules-degrading-faster-than-expected-research-finds/.

[80] U.S. Energy Information Administration, "Electricity Market Module," Assumptions to the Annual Energy Outlook 2022, March 2022, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

trend whereby wind turbines are repowered after just 10 to 12 years to recapture the wind Production Tax Credit (PTC). This trend will almost certainly grow in response to IRA subsidies.

EPA does not appear to take repowering into consideration because the amount of existing wind on its systems never changes. If our understanding of EPA's methodology is accurate, this a large oversight that must be corrected.

Fuel Cost Assumptions

Fuel costs for existing power facilities were estimated using FERC Form 1 filings and adjusted for current fuel prices.[81,82] Fuel prices for new natural gas power plants were estimated by averaging annual fuel costs within the MISO region according to EPA.[83] Existing coal fuel cost assumptions of $17.82 per MWh were based on 2020 FERC Form 1 filings.

Inflation Reduction Act (IRA) Subsidies

Our analysis assumes all wind projects will qualify for IRA subsidies and elect the Production Tax Credit, valued at $27.50 per MWh throughout the model run. Solar facilities are assumed to select the Investment Tax Credit in an amount of 30 percent of the capital cost of the project.

Appendix 2: Capacity Retirements and Additions in Each Scenario

This section details the capacity additions and retirements in the MISO region under each scenario.

Status Quo scenario: The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. Additions in the Status Quo scenario consist of 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.

Annual retirement and additions can be seen in Figure D-13 below.

[81] Trading Economics, "Natural Gas," https://tradingeconomics.com/commodity/natural-gas.
[82] https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region
[83] U.S. Energy Information Administration, "Open Data," https://www.eia.gov/opendata/v1/qb.php?category=40694&sdid=SEDS.NUEGD.WI.A

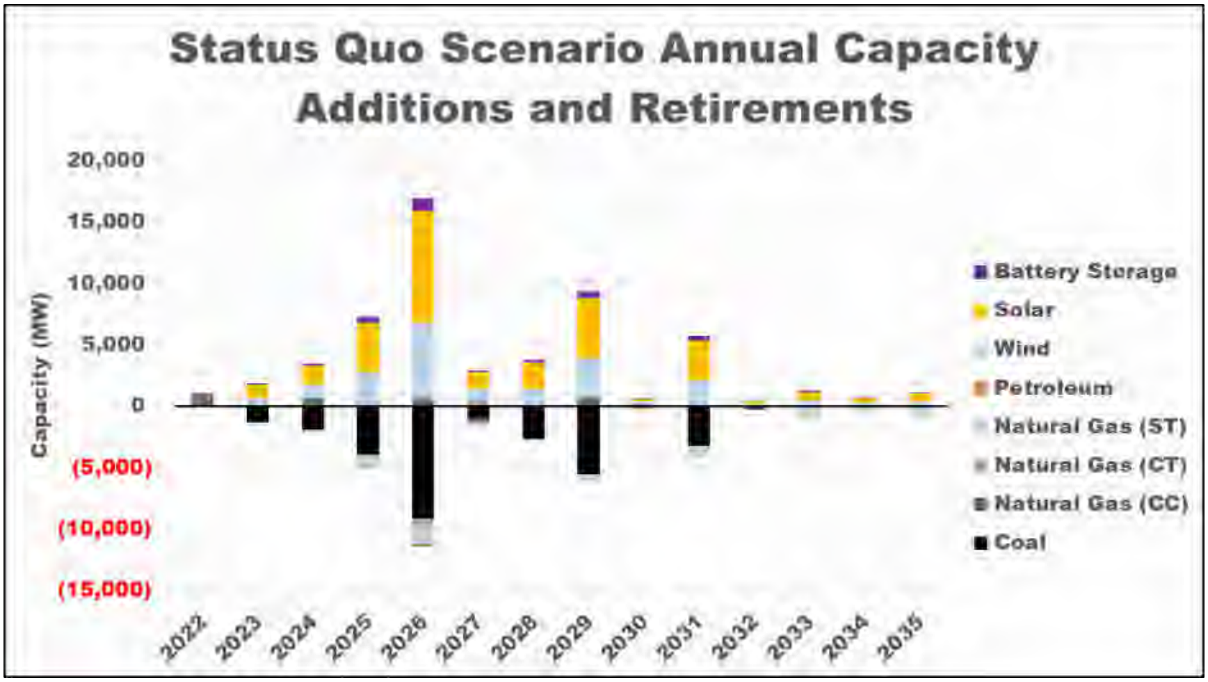


Figure D-13. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

Partial scenario: The Partial scenario results in the retirement of 29,908 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Partial scenario consist of 4,306 MW of natural gas, 20,451 MW of wind, 31,201 MW of solar, and 3,477 MW of storage (see Figure D-14). The incremental closure of 1,151 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage (see Figure D-15).[84]

[84] Replacement capacity is more than the retiring 1,151 MW of coal capacity because intermittent resources like wind and solar have lower capacity values than coal capacity.

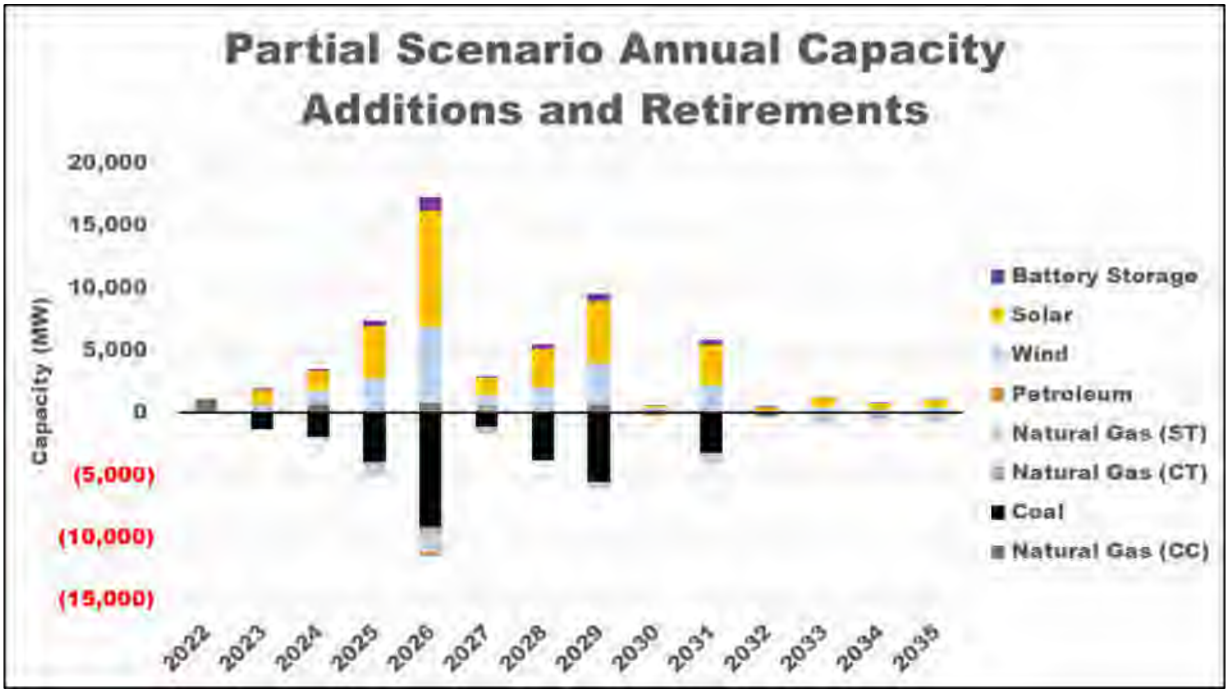


Figure D-14. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

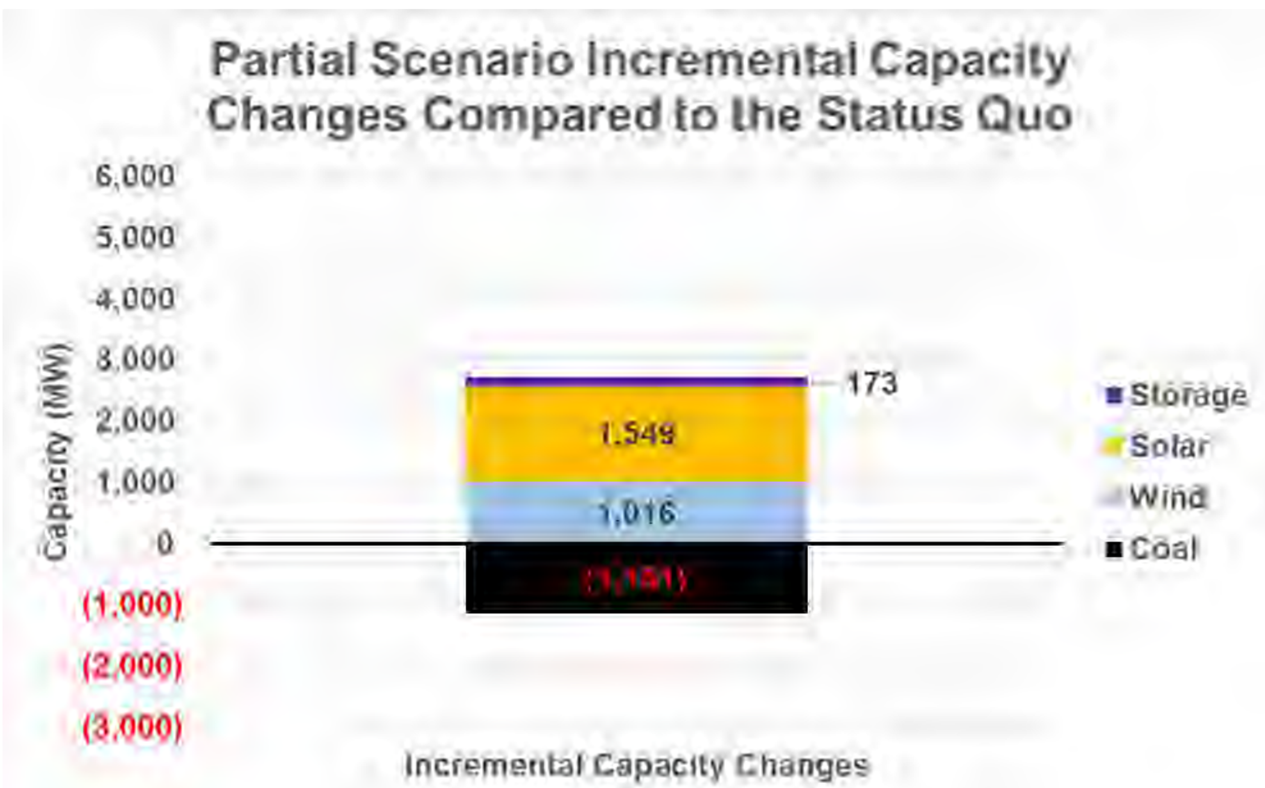


Figure D-15. This figure shows the incremental capacity retirements and additions in the MISO region under the Partial scenario.

Full Scenario: The Full scenario results in the retirement of 31,021 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Full scenario consist of 4,306 MW of natural gas, 21,433 MW of wind, 32,700 MW of solar, and 3,644 MW of storage (see Figure D-16). The incremental closure of 2,264 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage, compared to the Status Quo scenario (see Figure D-17).

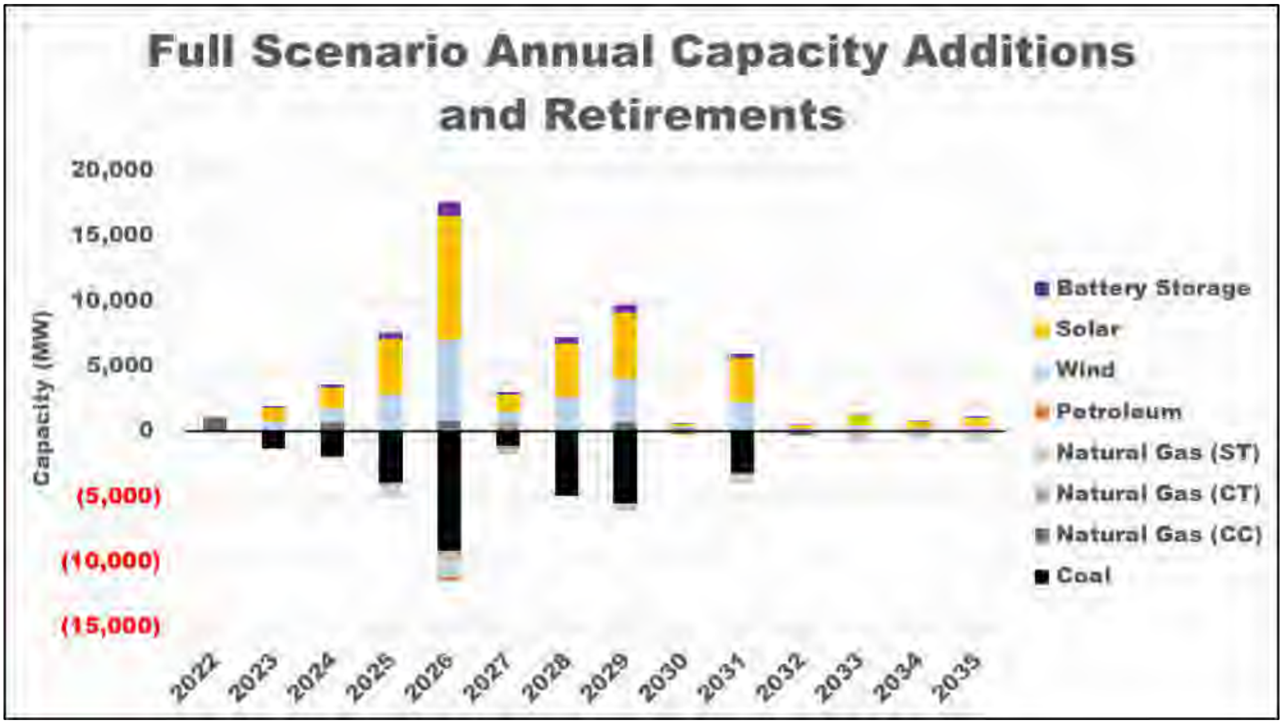


Figure D-16. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

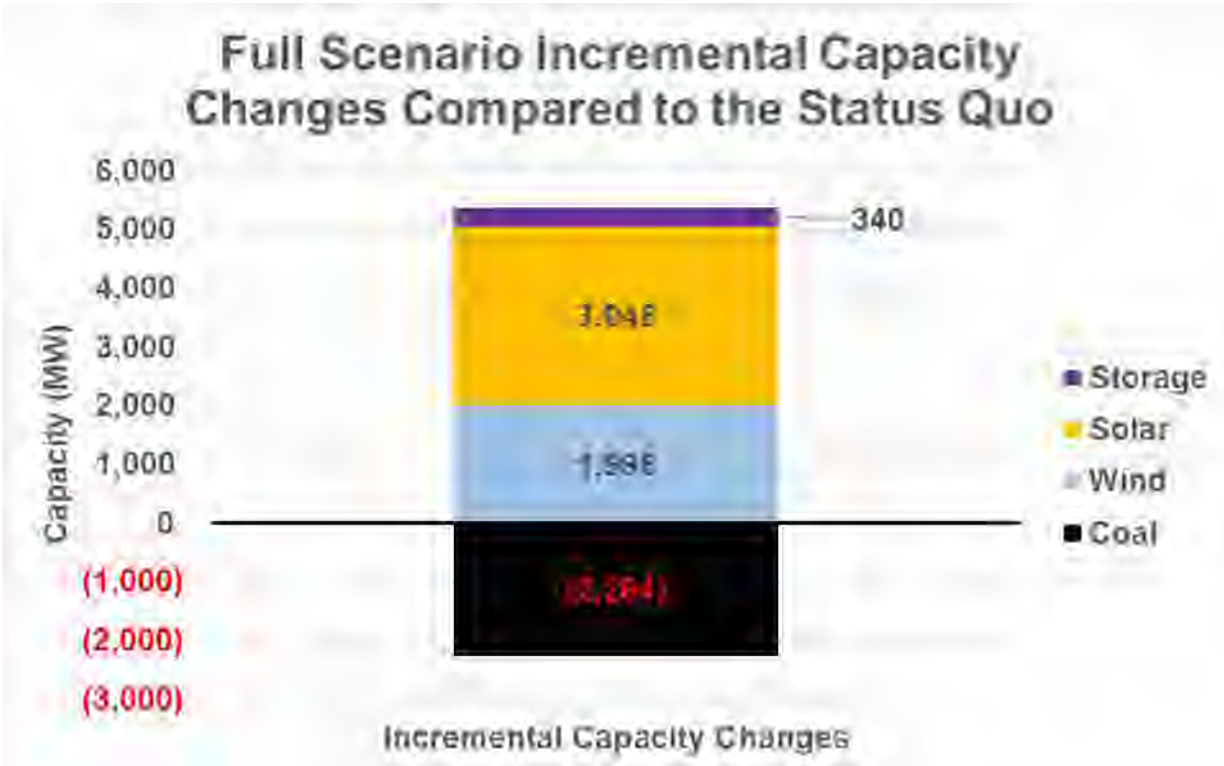


Figure D-17. This figure shows the incremental capacity closures and additions in the Full scenario.

Figure D-18 shows the capacity retirements and additions in the Partial and Full scenarios.

Comparison:

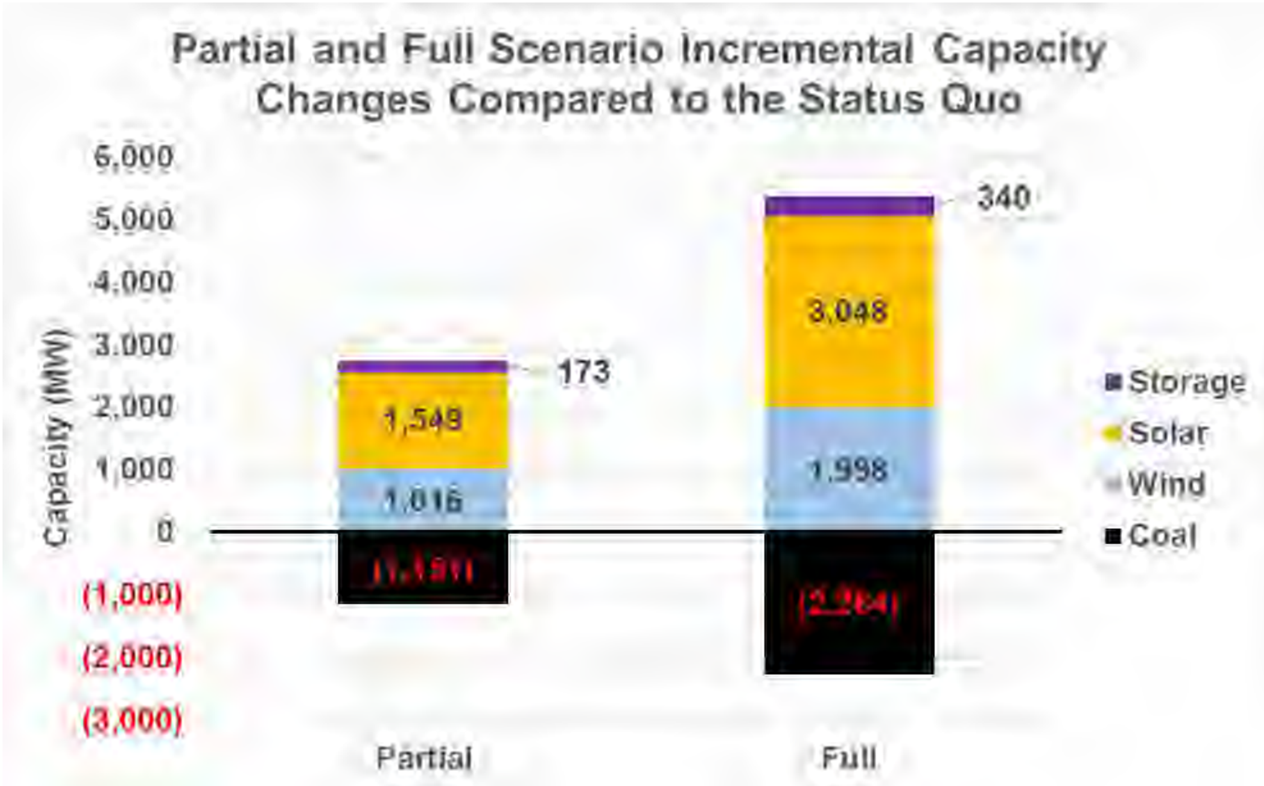


Figure D-18 comparison. This figure demonstrates the incremental retirements and additions in each scenario.

Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy

The capacity selected in our model to replace the retiring resources is based on two main factors. The first factor is the MISO interconnection queue, which is predominantly filled with solar and wind projects and a relatively small amount of natural gas. The second factor is the EPA's resource adequacy (RA) accreditation values in the Integrating Planning Model's (IPM) Proposed Rule Supply Resource Utilization file and Post-IRA Base Case found in the Regulatory Impact Analysis.

The IMP assumes a capacity accreditation of 100 percent for thermal resources, and variable intermittent technologies (primarily wind and solar) receive region-specific capacity credits to help meet target reserve margin constraints. Due to their variability, resources such as wind and solar received a lower capacity accreditation when solving for resource adequacy (see Table D-4).

EPA Integrated Planning Model

Capacity Accreditation in MISO

Resource	Capacity Value
Existing Wind	19%
Existing Solar	55%
New Onshore Wind 2035	17%
New Solar 2035	52%
Thermal	100%
Battery Storage	100%

Table D-4. This figure shows the capacity values for each resource based on EPA's estimates in its IPM.

In order to determine whether the available blend of power generation sources will be able to meet projected demand, each available generation source is multiplied against its capacity value, and the available resources are then "stacked" to determine if there is enough accredited power generation capacity to meet projected demand and maintain resource adequacy.

It should be noted that EPA's accreditation values from the IPM are generous compared to the accreditation values given by RTOs. For example, in the MISO region, grid planners assume that dispatchable thermal resources like coal, natural gas, and nuclear power plants will be able to produce electricity 90 percent of the time when the power is needed most, resulting in a UCAP rating of 90 percent. In contrast, MISO believes wind resources will only provide about 18.1 percent of their potential output during summer peak times, and solar facilities will produce 50 percent of their potential output. This report uses the generous capacity values provided by EPA; however, if the capacity values used by the RTOs were to be utilized, the projected energy shortfalls and blackouts would be even worse.

Appendix 4: Resource Adequacy in Each Scenario

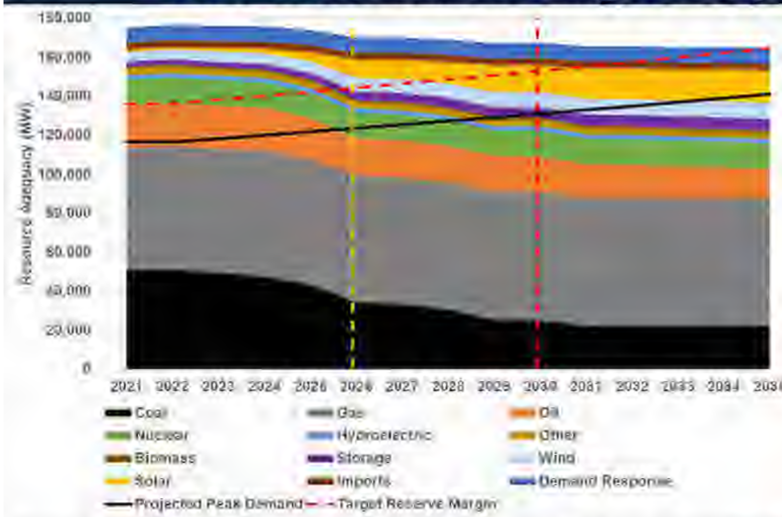
We performed a Resource Adequacy analysis on each of the three scenarios modeled to determine the potential impact to grid reliability in MISO region if implementation of the MATS Rule results in the forced retirement of lignite power plants.

Status Quo scenario

Under the Status Quo scenario, there is enough dispatchable capacity in MISO to meet the projected peak demand and target reserve margin established by EPA in the RIA documents

Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-19.[85]

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	12%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	96%
2031	18%	4%	94%
2032	16%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage, and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

Figure D-19. By 2030, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

Beginning in 2026, MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin, but the RTO still has enough dispatchable capacity to meet its projected peak demand. By 2030, the MISO region will rely on thermal resources and 4-hour battery storage to meet its peak demand, and by 2031 the region will no longer have enough dispatchable capacity or storage to meet its projected peak demand, and it will rely exclusively on non-dispatchable resources and imports to meet its target reserve margin.[86]

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-20 below. By 2035, dispatchable capacity consisting of thermal generation and battery storage will only be able to provide 91 percent of the projected peak demand, necessitating the use of wind and solar to maintain resource adequacy.

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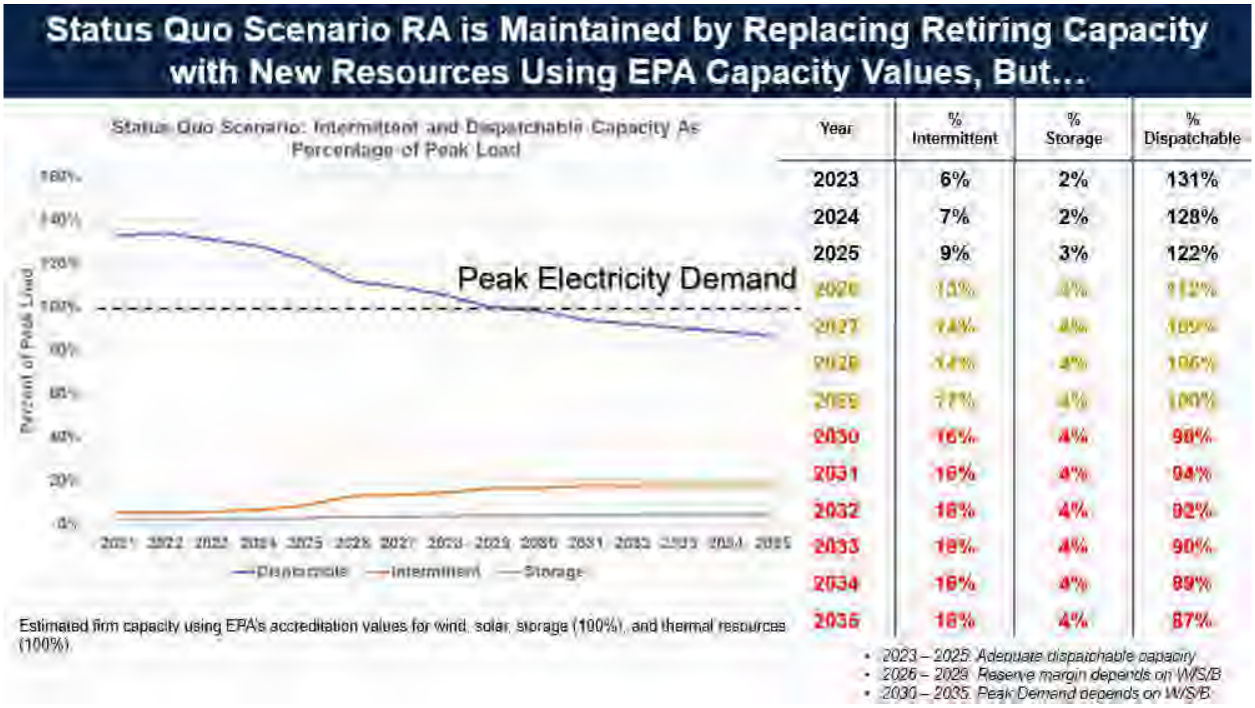
[85] Analysis of the Proposed MATS Risk and Technology Review (RTR) | US EPA, https://www.epa.gov/power-sector-modeling/analysis-proposed-mats-risk-and-technology-review-rtr

[86] While battery storage is considered dispatchable in this analysis for the sake of simplicity, battery resources are not a substitute for generation because as grids become more reliant upon wind and solar, battery resources may not be sufficiently charged to provide the needed dispatchable power.

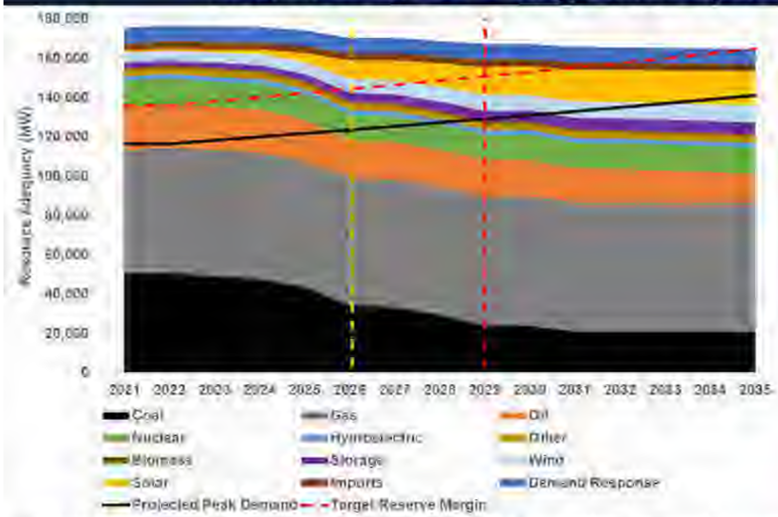


D-20. By 2035, dispatchable generators will only constitute 87 percent of projected peak demand, with storage accounting for four percent of peak demand capacity.

Partial scenario

Like the Status Quo Scenario, there is enough dispatchable capacity in MISO under the Partial scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-21.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	108%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

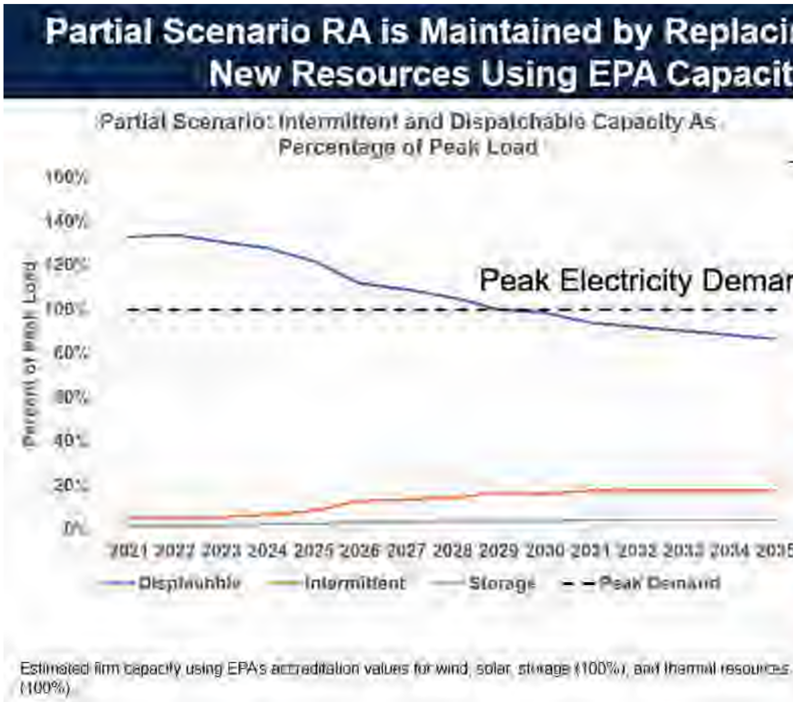
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-21. By 2029, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 105 percent in the Partial scenario, reflecting the loss of 1,151 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports, or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-22 below. By 2035, dispatchable capacity will only be able to provide 86 percent of the projected peak demand.



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	108%
2028	15%	[illegible]	[illegible]
2029	17%	4%	99%
2030	17%	4%	96%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

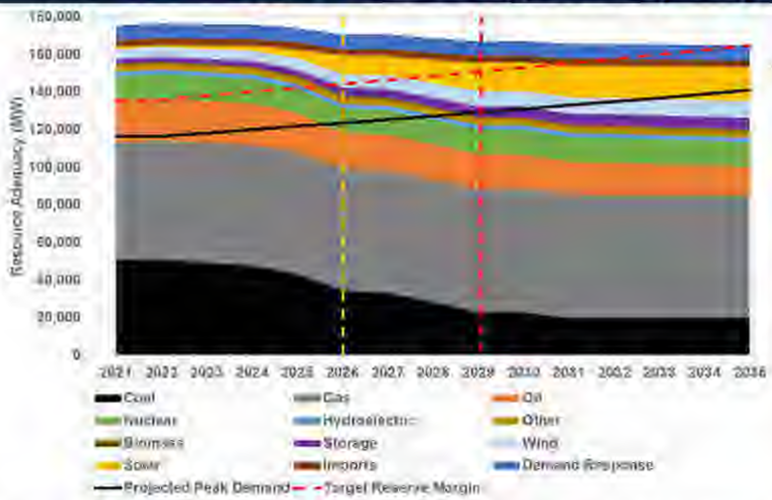
- 2023 – 2025: Adequate dispatchable capacity
- 2026 – 2028: Reserve margin depends on W/S/B
- 2029 – 2035: Peak Demand depends on W/S/B

Figure D-22. The percentage of peak electricity demand being served by dispatchable resources drops by one percent in 2028, relative to the Status Quo scenario, due to the closure of lignite capacity in MISO due to the MATS rule.

Full scenario

Like the Status Quo scenario and Partial scenario, there is enough dispatchable capacity in MISO under the Full scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-23.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-23. The amount of dispatchable capacity available to meet projected peak demand in 2028 falls from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the closure of all the lignite capacity in MISO that year.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the loss of 2,264 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-24 below. By 2035, dispatchable capacity will only be able to provide 85 percent of the projected peak demand, a two percent decline relative to the Status Quo scenario, necessitating the use of wind and solar to maintain resource adequacy.

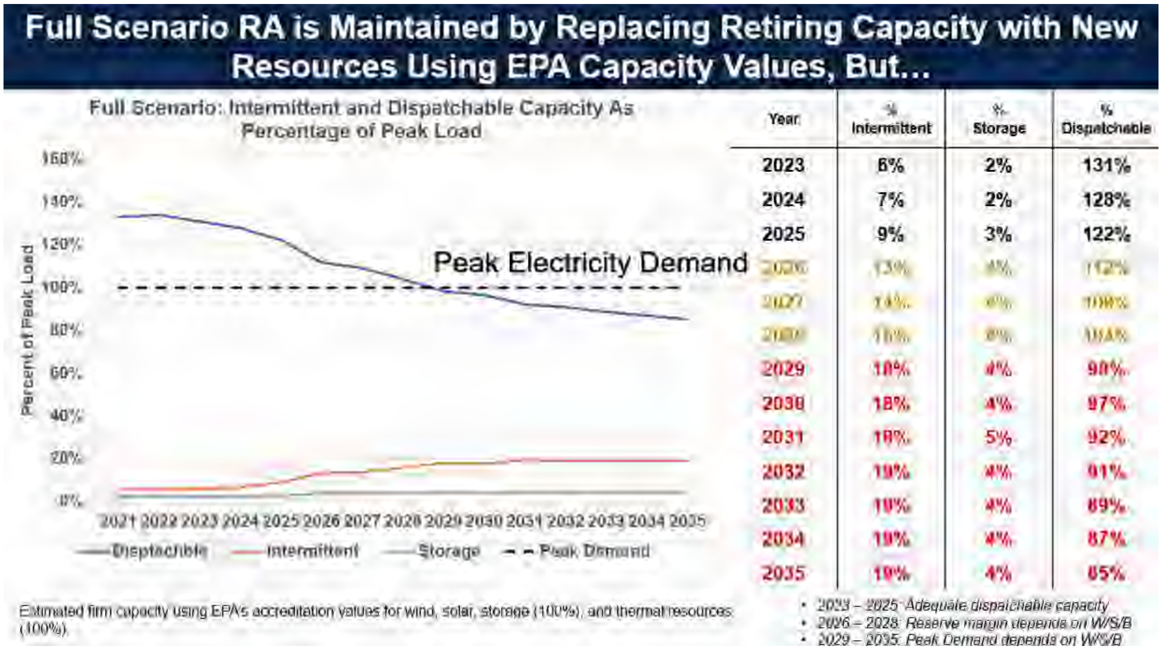


Figure D-24. The amount of peak demand that can be met with dispatchable resources in 2028 falls from 106 in the Status Quo scenario to 104 in the Full scenario.

Attachment B

to the Declaration of Christopher D. Friez

NDSU Agribusiness and Applied Economics Report No. 819-S March 2023

North Dakota Lignite Energy Industry

Economic Contribution Analysis

Report Content

Preface

This report is the latest biennial assessment of the economic contribution of the North Dakota lignite energy industry.

Data for this study came from industry surveys, state and federal agencies, and other secondary sources,

The definition of the lignite energy industry and methods used to estimate its economic contribution are consistent with studies examining the economic contribution of other industries in the state. As usual, these studies are snapshots in time and economic contributions often vary from year to year with commodity-based industries.

Industry Highlights

The following figures are based on activity during 2021 and projections of industry output in 2022. All values include direct and secondary economic effects.

North Dakota Lignite Energy Industry in 2021

- $5.64 billion gross business volume
  - $0.9 billion from mining
  - $3.2 billion from coal conversion and electricity generation
  - $1.5 billion from transmission/distribution
- 12,800 jobs (direct and secondary)
  - 3,300 jobs supported by mining
  - 8,400 jobs supported by coal conversion and electricity generation
  - 1,050 jobs supported by transmission/distribution
- $119 million in local and state government revenues

North Dakota Lignite Energy Industry in 2022

- $5.75 billion gross business volume
  - $0.8 billion from mining
  - $3.2 billion from coal conversion and electricity generation
  - $1.7 billion from transmission/distribution
- 12,000 jobs (direct and secondary)
  - 3,250 jobs supported by mining
  - 7,725 jobs supported by coal conversion and electricity generation
  - 1,060 jobs supported by transmission/distribution
- $104 million in local and state government revenues

**Bangsund is a Research Scientist, Department of Agribusiness and Applied Economics and Hodur is Director, Center for Social Research, North Dakota State University

Understanding the Numbers

Economic contribution assessments measure the gross size of an industry or economic sector.

Size is estimated by combining ***direct*** or first-round effects (i.e., sales, spending, and/or employment) with economic modeling to estimate secondary effects of business-to-business transactions (***indirect***) and household spending for goods and services (***induced***).

Economic measures frequently used in economic contribution assessments:
❖ **Labor income** – earnings of workers and sole proprietors
❖ **Employment** – wage and salary jobs and sole proprietor/self-employed jobs
❖ **Gross business volume** – includes direct sales of products and services of the industry being measured, and sum of all business-to-business and household-to-business transactions associated with indirect and induced economic activity
❖ **Value-added** – represents share of gross state product

An overview and additional information on study methods, data sources, and economic definitions are appended to the end of this report.

Composition of Lignite Energy Industry

Coal Mining: this segment involves the process of extracting lignite coal and delivering it to conversion facilities.

Coal Gasification: this segment involves converting lignite coal into chemicals and other products. It is grouped with electricity generation segment of the industry.

Electricity Generation: this segment burns lignite coal to produce electricity.

Transmission and Distribution: this segment includes moving electricity to local (in-state) distributors and exporting electricity to out-of-state markets.

Industry Contribution 2021

Coal mining had 1,131 direct jobs; business activity relating to coal mining operations supported another 1,220 jobs. Personal spending on goods and services by employees working in the coal mining sector and employees of businesses affected by coal mining supported an additional 960 jobs. The combined effects on statewide employment from coal mining was estimated at 3,300 jobs. Other economic effects from coal mining included $300 million in labor income and $915 million in gross business volume.

Coal conversion and electricity generation from lignite was estimated to have nearly 1,700 direct jobs, and business activity relating to those lignite operations supported another 4,680 jobs. Personal spending on goods and services by employees working in the coal conversion and generation activities and employees of businesses affected by those activities supported an additional 2,070 jobs. The combined direct, indirect, and induced effects on statewide employment from coal conversion and electricity generation was estimated at 8,400 jobs. Other economic effects from coal conversion and electricity generation included $670 million in labor income and nearly $3.2 billion in gross business volume.

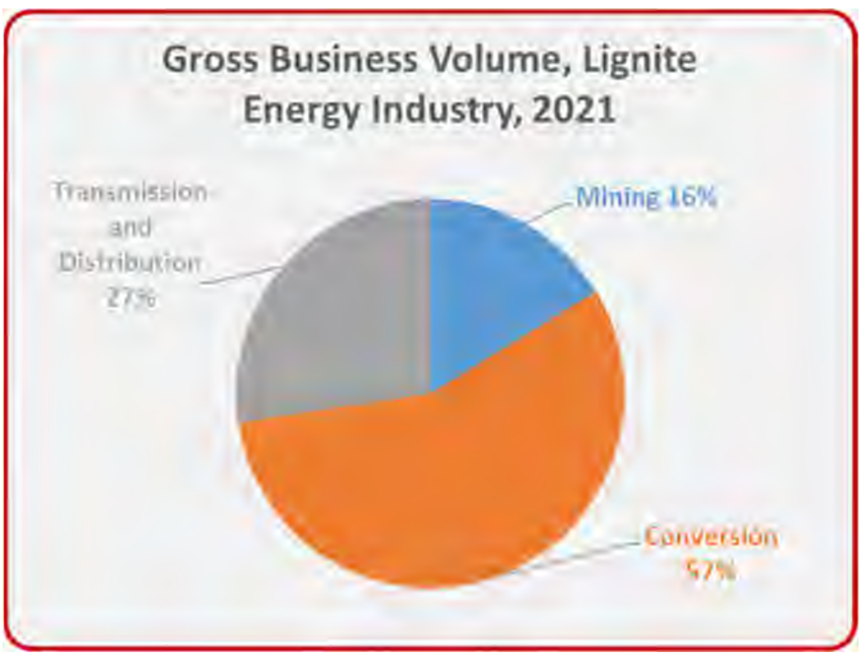
Electricity transmission and generation from lignite-based activities was estimated to have 480 direct jobs; business activity relating to those lignite operations supported another 290 jobs. Personal spending on goods and services by employees working in coal-related electricity transmission and distribution and employees of businesses affected by those activities supported an additional 280 jobs. The combined direct, indirect, and induced effects on statewide employment from coal-related electricity transmission and distribution was estimated at 1,060 jobs. Other economic effects from transmission and distribution included $84 million in labor income and $1.5 billion in gross business volume.

The combination of coal mining, coal conversion, coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,300 direct jobs in North Dakota in 2021. These lignite coal activities supported about 6,190 jobs through business purchases of goods and services in the state. The combined personal spending of employees in the Lignite Industry, and employees of businesses involved with supplying goods and services to the industry supported another 3,310 jobs. Collectively, the industry was estimated to support 12,800 jobs in the state.

The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income. The industry also contributed $2 billion to the state's gross domestic product, and the industry's gross business volume was estimated at $5.6 billion.

Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2021				
Industry Segment/Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
Coal Mining		---------------------- millions 2021 $	----------------------	
Direct effects	1,131	165	227	560
Indirect effects	1,220	84	152	270
Induced effects	960	51	84	85
Total economic effects	3,311	300	463	915
Electricity Generation and Coal Conversion				
Direct effects	1,694	228	240	1,728
Indirect effects	4,680	332	568	1,120
Induced effects	2,070	110	182	331
Total economic effects	8,444	671	990	3,178
Electricity Transmission and Distribution				
Direct effects	483	50	453	1,386
Indirect effects	290	19	69	111
Induced effects	285	15	25	45
Total economic effects	1,058	84	547	1,543

[1] Employment represents total jobs, and does not represent employment in FTE.



Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2021

Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
ND Lignite Industry		---------- millions 2021 $ ----------		
Direct	3,308	443	919	3,674
Indirect	6,190	436	789	1,501
Induced	3,310	177	291	461
Total	**12,808**	**1,056**	**1,999**	**5,636**

[1] Employment represents total jobs, and does not represent employment in FTE.

Industry Contribution 2022 (projected)

The following figures and values were based on an industry survey soliciting estimates of calendar year 2022 business activities, although the survey was administered prior to yearend. Firms were asked to estimate what their 2022 revenues and expenditures would be based on data available at the time of the survey and augment that information with expected activities for the remaining months in 2022. Data provided by the industry for 2022 is treated as a projection. However, the projection is considered a reasonable estimate of 2022 since, in many cases, the estimates included actual revenues and expenditures for 10 to 11 months of 2022.

Coal mining had 1,170 direct jobs; business activity relating to coal mining operations supported another 1,090 jobs. Personal spending on goods and services by employees working in the coal mining sector and employees of businesses affected by coal mining supported an additional 990 jobs. The combined effects on statewide employment from coal mining was estimated at 3,250 jobs. Other economic effects from coal mining included $300 million in labor income and $830 million in gross business volume.

Coal conversion and electricity generation from lignite was estimated to have 1,630 direct jobs, and business activity relating to those lignite operations supported another 4,240 jobs. Personal spending on goods and services by employees working in the coal conversion and generation activities and employees of businesses affected by those activities supported an additional 1,850 jobs. The combined direct, indirect, and induced effects on statewide employment from coal conversion and electricity generation was estimated at 7,720 jobs. Other economic effects from coal conversion and electricity generation included $620 million in labor income and over $3.2 billion in gross business volume.

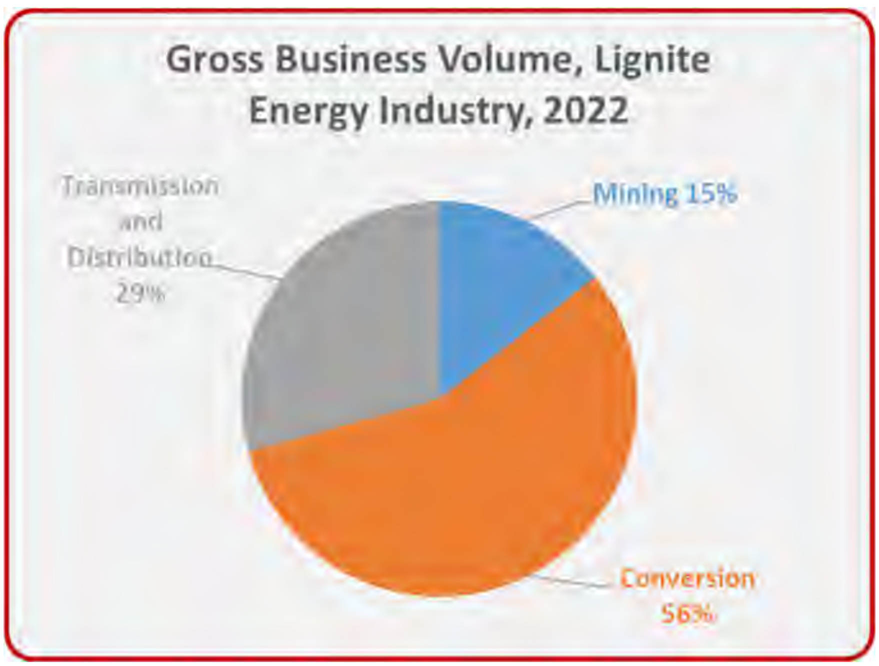
Electricity transmission and generation from lignite-based activities was estimated at 470 direct jobs; business activity relating to those lignite operations supported another 300 jobs. Personal spending on goods and services by employees working in coal-related electricity transmission and distribution and employees of businesses affected by those activities supported an additional 280 jobs. The combined direct, indirect, and induced effects on statewide employment from coal-related electricity transmission and distribution was estimated at 1,050 jobs. Other economic effects from transmission and distribution included $86 million in labor income and $1.7 billion in gross business volume.

The combination of coal mining, coal conversion, lignite coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,270 direct jobs in North Dakota in 2022. These lignite coal activities supported about 5,630 jobs through business purchases of goods and services in the state. The combined personal spending of employees in the Lignite Industry, and employees of businesses involved with supplying goods and services to the industry supported another 3,120 jobs. Collectively, the industry was estimated to support 12,020 jobs in the state.

The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income. The industry also contributed nearly $2.2 billion to the state's gross domestic product, and the industry's gross business volume was estimated at $5.8 billion.

Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, Projected 2022				
Industry Segment/Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
Coal Mining		------------------- millions 2022 $ -------------------		
Direct effects	1,168	177	219	537
Indirect effects	1,090	76	123	207
Induced effects	990	53	87	88
Total economic effects	3,248	306	430	832
Electricity Generation and Coal Conversion				
Direct effects	1,633	225	510	2,008
Indirect effects	4,240	295	534	935
Induced effects	1,850	99	163	297
Total economic effects	7,723	619	1,208	3,239
Electricity Transmission and Distribution				
Direct effects	473	51	473	1,525
Indirect effects	300	20	47	116
Induced effects	280	15	25	45
Total economic effects	1,053	86	545	1,687

[1] Employment represents total jobs, and does not represent employment in FTE.



Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2022 (projected)				
Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
ND Lignite Industry		---------------------- millions 2022 $	----------------------	
Direct	3,274	453	1,202	4,070
Indirect	5,630	391	704	1,258
Induced	3,120	167	275	430
Total	**12,024**	**1,011**	**2,182**	**5,758**

[1] Employment represents total jobs, and does not represent employment in FTE.

Government Revenues 2021

Government revenues are often used as a measure of how effectively an industry supports public services. In North Dakota, the most common sources of in-state public revenues are severance taxes, sales and use taxes, property taxes, and income taxes. A host of other taxes and revenue sources are often tracked in economic contribution and impact assessments, but those sources have varying levels of contribution to government revenue.

The lignite industry was estimated to contribute $64.5 million in government revenues directly from the firms in the industry. Tax revenues arising from secondary business activity were estimated to generate an additional $54.5 million in state and local government revenues. A total of $119 million in state and local tax revenues were generated by the Lignite Industry in North Dakota in 2021.

Coal conversion and coal severance taxes were estimated at $26.5 million. Other substantial contributions to state and local government revenues from secondary economic effects were from sales taxes ($25 million) and property taxes ($19.5 million).

State and Local Government Revenues, Lignite Industry, North Dakota, 2021

Government Revenue	Paid Directly by the Industry	Collected from Indirect and Induced Activity	Total Collections
	---------------------- 000s 2021 $ ----------------------		
Coal Severance Tax	10,518	---	10,518
Coal Conversion Tax	15,991	---	15,991
Sales, Property, and Corporate Income Taxes (reported in survey data)	25,861	---	25,861
Social Insurance Tax	1,952	1,247	3,200
Personal Income Tax	3,039	2,377	5,416
Sales Tax	see above	25,336	25,336
Property Tax	see above	19,531	19,531
Corporate Income Tax	see above	1,362	1,362
Other Taxes	2,666	1,438	4,104
Non Taxes	4,568	3,222	7,789
Totals	**64,595**	**54,512**	**119,107**

Government Revenues 2022 (projected)

The lignite industry was projected to contribute $53 million in government revenues directly from the firms in the industry. Tax revenues arising from secondary business activity, based on projections of industry activity, were estimated to generate an additional $50.6 million in government revenues. A projected total of $103.5 million in state and local tax revenues were created by the Lignite Industry in North Dakota in 2022.

Coal conversion and coal severance taxes were estimated at $15.8 million. Other substantial contributions to state and local government revenues from secondary economic effects were from sales taxes ($23.5 million) and property taxes ($18 million).

State and Local Government Revenues, Lignite Industry, North Dakota, 2022 (projected)

Government Revenue	Paid Directly by the Industry	Collected from Indirect and Induced Activity	Total Collections
	---------------------- 000s 2022 $	----------------------	
Coal Severance Tax	10,450	---	10,450
Coal Conversion Tax	5,360	---	5,360
Sales, Property, and Corporate Income Taxes (reported in survey data)	25,667	---	25,667
Social Insurance Tax	1,996	1,183	3,179
Personal Income Tax	3,107	2,264	5,371
Sales Tax	see above	23,457	23,457
Property Tax	see above	18,082	18,082
Corporate Income Tax	see above	1,310	1,310
Other Taxes	2,349	1,331	3,680
Non Taxes	4,024	3,003	7,027
Totals	**52,953**	**50,630**	**103,583**

Share of State Economy

A key means of placing an industry contribution study into context is showing its share of a broader economy. The lignite energy industry represents an important share of the North Dakota's economy. The lignite energy industry represented 2.6 percent of the state's gross state product and 4 percent of the state's gross business volume. The industry represented about 2.8 percent of the state's total labor income. The industry represents about 1.2 percent of all state and local government revenues.

The lignite energy industry share of employment was 2.3 percent of statewide employment. Those shares are based on a state total for both wage and salary jobs and sole proprietors/self employed jobs. The industry's share of the state economy was not estimated for 2022 as state-level data was unavailable prior to completing the study.

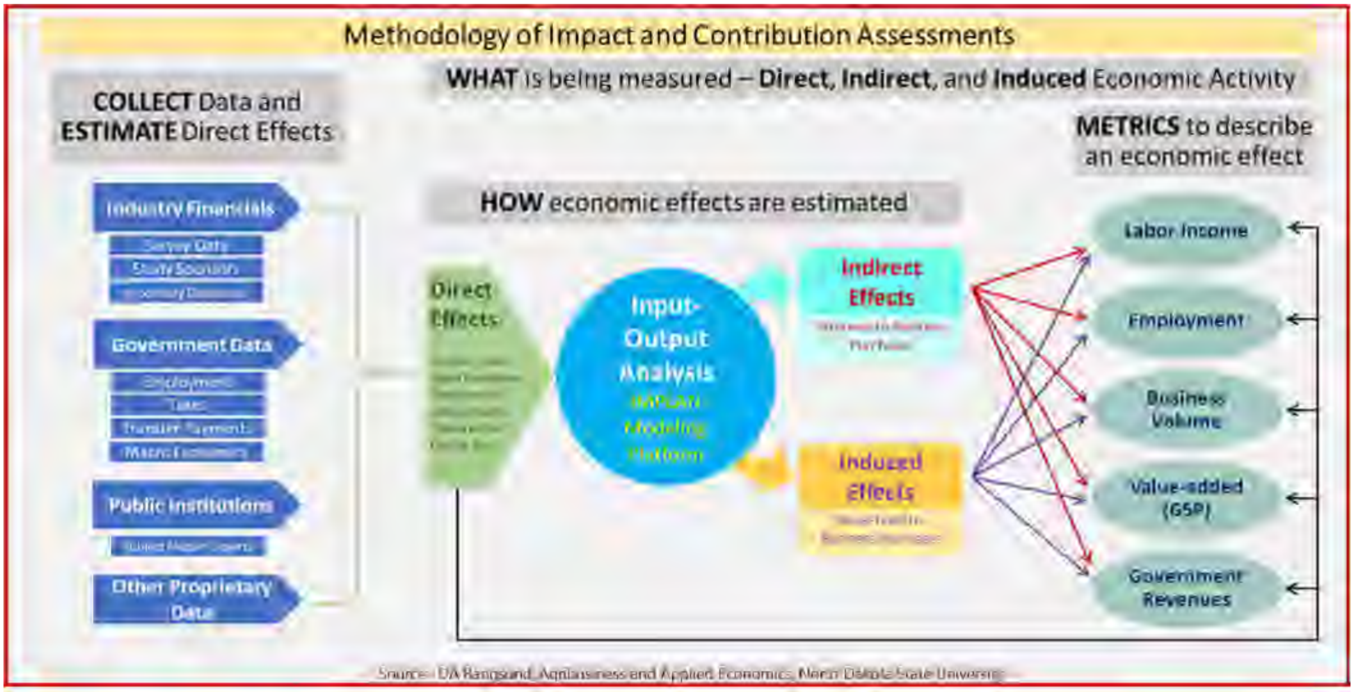
ANNUAL SHARE OF STATE TOTALS, North Dakota Lignite Energy Industry				
Industry Segment	Labor Income	Value-added (GSP)	Total Output	State and Local Government Revenues
State-level Values for 2021	$37.3 billion	$77.0 billion	$142.7 billion	$9.954 billion
Mining	0.81%	0.60%	0.64%	---
Conversion	1.80%	1.29%	2.23%	---
Transmission and Distribution	0.23%	0.71%	1.08%	---
All Segments	2.83%	2.60%	3.95%	1.20%

ANNUAL SHARE OF STATE EMPLOYMENT, North Dakota Lignite Energy Industry			
Industry Segment	Total Employment	Wage and Salary	Self-employed
State-level Values for 2021	557,702	434,811	122,691
Mining	0.59	3184#	3175#
Conversion	1.51	31k<#	31;9#
Transmission and Distribution	0.19	314:#	313;#
		#	#
All Segments	2.30%	419:(#	4169(#

Supplemental Materials

Economic Contribution Analysis

An economic contribution assessment measures the gross size of some aspect or component of an economy, and is usually measured in conjunction with the overall size of a given economy over a specified period. Size is estimated by combining direct or first-round effects (e.g., industry expenditures, business sales, new employment) with economic modeling to estimate how those first round effects generate business-to-business transactions and household spending on consumer goods and services. Both of those conduits for economic output can be framed using labor income, employment, value-added, gross business volume and government revenues.



Key Terms and Concepts

Direct Effects: First-round of payments for services, labor, and materials and/or sales of an industry's products.

Indirect Effects: Economic activity created through purchases of goods and services by businesses.

Induced Effects: Economic activity created through purchases of goods and services by households.

Industry Output and Gross Business Volume: Industry output is the value of all goods and services produced and supported by an industry. In most industries, output is largely synonymous with sales; however, for some sectors output also includes changes in product inventory. For lignite energy industry, direct output includes both sales and inventory adjustments.

When output from business-to-business transactions (*indirect*) and households-to-businesses (*induced*) are measured, they also are described as the *sum of gross receipts* as annual adjustments to inventories are largely unquantified and not distinguished from sales. *Gross business volume* (GBV) therefore includes direct output/sales and includes secondary sales from indirect and induced economic activity.

Value-added: Value-added is synonymous with measures of gross domestic product (GDP) and gross state product (GSP), are some of the most commonly used economic measures to indicate the economic size and change in economic output. However, official government estimates of GDP and GSP do not include secondary economic effects generated by any industry. For lignite energy industry, official government estimates are primarily limited to coal mining, coal conversion, and transmission/distribution. Economic contribution assessments include secondary economic effects, and include GSP from those effects, thereby providing a more realistic and representative portrait of an industry.

Key components of value-added include labor income, consumption of fixed capital, profits, business current transfer payments (net), and income derived from dividends, royalties, and interest. In nontechnical terms, value-added is equal to product value minus production inputs. For example, value-added from coal mining would be the value of coal sold less the value of the inputs consumed in mining the coal. Depreciation charged to durable assets (e.g., buildings, pipelines, processing equipment) are not included in value-added measures.

Employment Compensation: Wages, salaries, and benefits earned by an employee.

Proprietor Income: Payments received by self-employed individuals and unincorporated business owner/operators.

Labor Income: Wages, salaries, and benefits for employees and compensation for self-employed individuals.

Input-output Analysis (I-O): Mathematical application of the interdependence among producing and consuming sectors in an economy.

I-O Matrix: Depiction of an economy using a grid of rows and columns that represents consumption and production for each economic sector in an economy.

Intermediate Inputs: Goods and services consumed in one year to produce another good or service. Intermediate inputs do not include expenditures for capital inputs used for multiple production seasons (e.g., machinery, buildings).

Capital Inputs: Represent the use of inputs to produce another good or service that are not consumed in one production season and are subject to depreciation. *Capital expenditures* represent the purchase of those depreciable assets.

Industry Balance Sheet: Dividing an industry or economic sector into various components for use in estimating the economic effects using input-output analysis. Components of the balance sheet include measures of output, wage and salary employment, self-employment, payroll and proprietor income, other property type income, taxes on production and imports, and intermediate inputs.

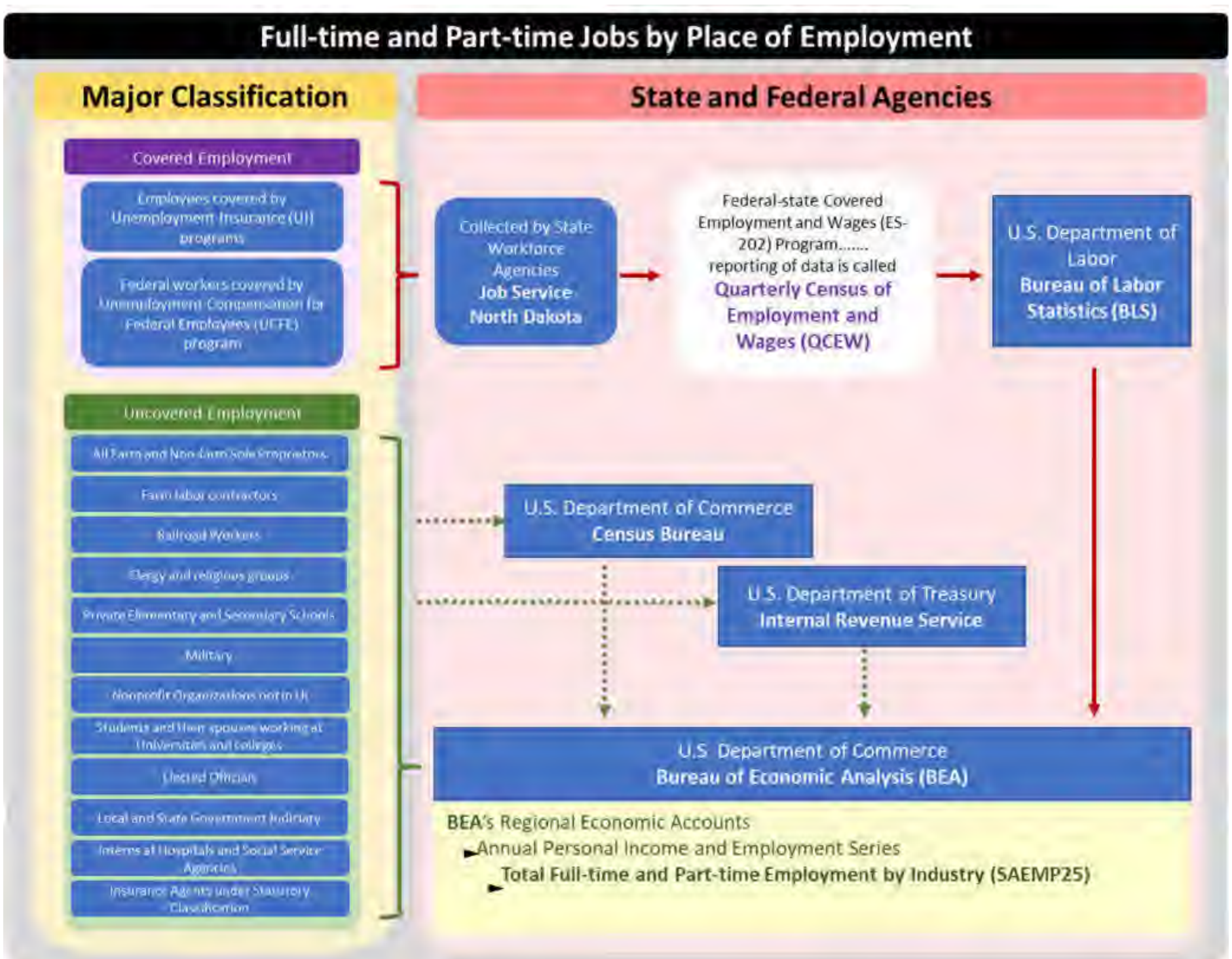
Institutions: Represent governments and other non-private entities consuming goods and services in an economy.

Households: Represent one or more individuals in a specific living arrangement for which income from all sources is used to purchase goods and services.

North American Industry Classification System (NAICS): Government classification system for all goods and services produced in the economy.

Employment Sources and Measures

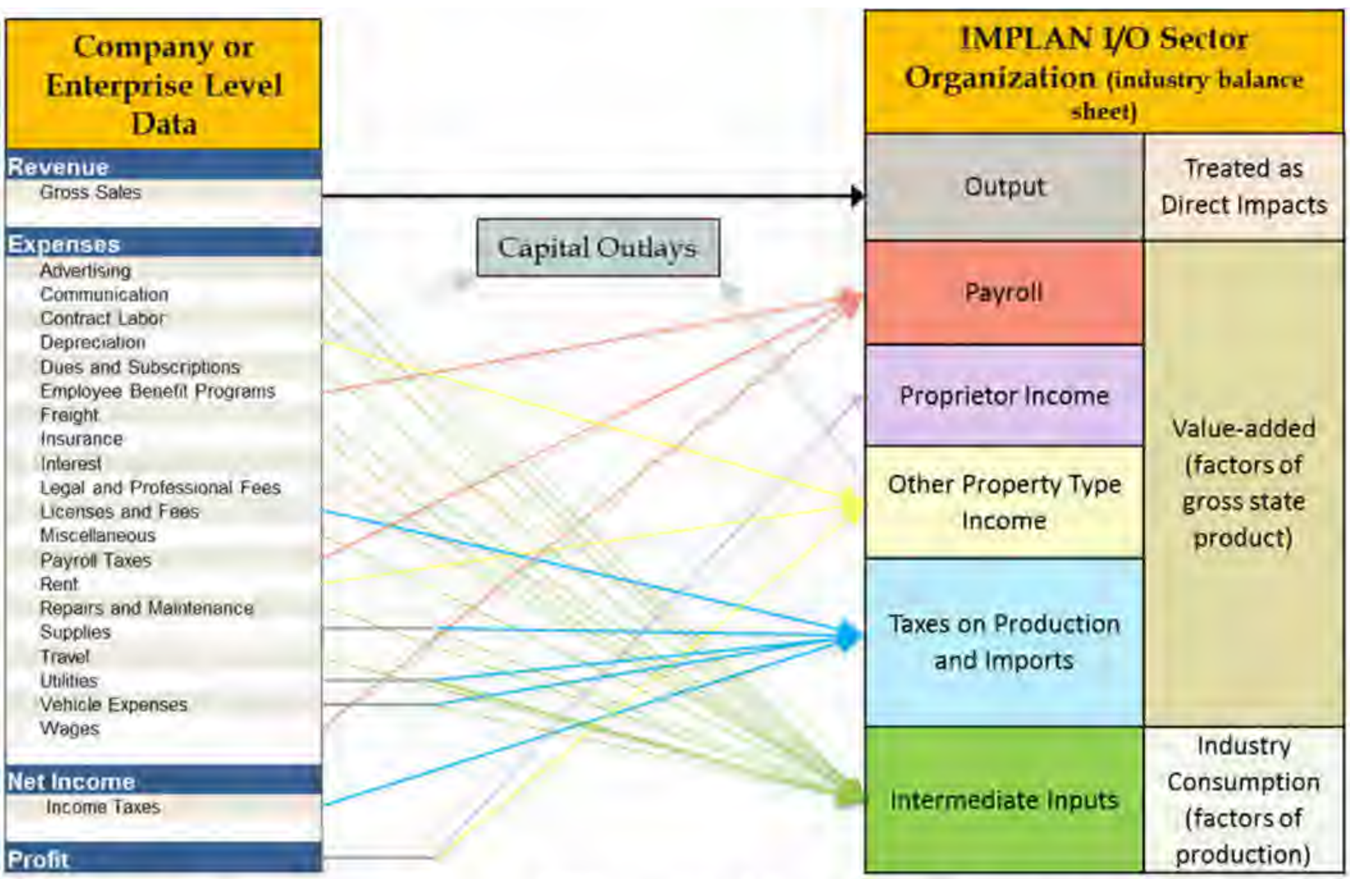
Employment is broadly measured in two distinct categories: covered and uncovered. Covered workers are those that are employed by a business, institution, or government agency, receive a wage or salary, and are subject to unemployment insurance (UI). Jobs that fall under an UI program are called 'covered' employment. Quarterly Census of Employment and Wages (QCEW) employment reported by Job Service North Dakota is 'covered' employment. QCEW data are collected for each state and reported by the U.S. Bureau of Labor Statistics (BLS). Therefore, employment statistics for self-employed individual cannot be derived from QCEW data.



Developing Economic Sector Profiles

An industry balance sheet or economic profile is one of the most important elements in economic contribution studies. Nearly all key economic metrics have their origin within an industry's economic profile/sector. Information and data to create economic sector profiles were collected from surveys of industry firms and data from government agencies.

While the IMPLAN modeling platform provides baseline economic profiles generated from proprietary estimation techniques applied to government data, this study relied on state-sourced data and industry input to create a customized IO matrix. The process of developing study-specific economic profiles and then modifying an IO matrix is time consuming and requires considerable empirical analysis, but the results from those efforts produce a credible and transparent evaluation of an industry's role in an economy.



General Transposition of Financial Information into IMPLAN Economic Sector Profiles

Source: DA Bangsund, Department of Agribusiness and Applied Economics, NDSU

Treatment of Traditional Economic Sectors Supporting Lignite Energy Industry

This summary omits specific details of how the secondary economic effects are distributed among the state's numerous economic sectors and sub-sectors. Several economic sectors support the lignite energy industry by providing inputs and services to various segments of the industry. Examples include manufacturing, financial institutions, legal representation, business services, industrial equipment and machinery, among others. Under some definitions, those activities and sectors are presented as "direct" segments of the industry. However, from the perspective of how this study's input-output analysis was structured, those sectors represent "indirect" economic output of the industry, meaning those sectors are supported and sustained from purchases relating to lignite energy industry mining, conversion, and transportation/distribution.

Acknowledgments

Special thanks are extended to Jason Bohrer, President, Lignite Energy Council, for his leadership, guidance, and information throughout the study, and to Kay LaCoe, Vice President of Communications, Lignite Energy Council who assisted with the surveys and soliciting industry cooperation for the study.

The study authors and study sponsors would like to thank all the companies and individuals that took the time to complete and return the survey materials. This study, with its reliance on industry data, would not have been possible without industry cooperation.

Financial support was provided by the North Dakota Lignite Energy Council. We express our appreciation for their support.

We wish to thank Edie Nelson, Department of Agribusiness and Applied Economics, for document preparation.

The authors assume responsibility for any errors of omission, logic, or otherwise. Any opinions, findings, and conclusions expressed in this publication are those of the authors and do not necessarily reflect the view of the NDSU Department of Agribusiness and Applied Economics or the NDSU Center for Social Research.

Exhibit 8

DECLARATION OF TAWNY BRIDGEFORD IN SUPPORT OF MOTION TO STAY FINAL RULE

I, Tawny Bridgeford, declare as follows:

1. My name is Tawny Bridgeford. I am the General Counsel & Senior Vice President, Regulatory Affairs for the National Mining Association ("NMA"). I make this declaration in support of NMA's motion to stay the U.S. Environmental Protection Agency's ("EPA") Final Rule titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 89 Fed. Reg. 38,508 (May 7, 2024) (hereinafter, the "Final Rule"). I am over the age of eighteen and have personal knowledge of the facts set forth below.

2. I have been employed by the NMA for over 19 years and have held my current position of General Counsel and Senior Vice President, Regulatory Affairs for 17 months. Since 2004, I have represented the NMA on legal, regulatory, and policy issues related to air, waste, and chemicals. I am currently responsible for managing the NMA's entire regulatory and litigation portfolio, including matters under the Clean Air Act.

3. The NMA is the national trade association that represents the interests of the mining industry, including every major coal company operating in the United States. In 2023, our member companies represented 75 percent of U.S. coal production in 18 states. The NMA has over 250 members, whose interests it represents before Congress, the administration, federal agencies, the courts, and the media. The NMA works to ensure America has secure and reliable supply chains, abundant and affordable energy, and the American-sourced materials necessary for U.S. manufacturing, national security, and economic security, all delivered under world-leading environmental, safety, and labor standards. As part of its core mission and purpose of representing NMA members' interests, the NMA advocates for sound regulatory policy decisions by the EPA and regularly participates in court cases challenging rules that harm the mining industry, such as the Final Rule.

4. Mining occupies a critical place in America's economy and energy infrastructure. In 2023, the coal mining industry fueled 16 percent of the Nation's electricity,[1] providing the fuel needed to generate

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[1] *See* Energy Information Administration (EIA), *Annual Energy Outlook 2023* (2023) (Table 7.2a: Electricity Net Generation: Total (All Sectors)), https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf.

affordable and reliable baseload power for households, businesses, manufacturing facilities, transportation and communications systems, and services throughout our economy. Likewise, the coal mining industry directly employs 100,000 people with 224,000 indirect coal mining jobs, and provides high-paying jobs to American workers. For example, the average annual wage for all U.S. coal miners is $102,855—46 percent above the average wage for all U.S. workers, which is $70,343. Millions of dollars in federal, state, and local taxes can be attributed to mining jobs, and coal mining directly contributed over $31 billion to GDP in 2023.[2] While coal mining often takes place in locations with per capita incomes well below and poverty rates well above national and state averages, coal mining jobs are among the best-paying blue collar jobs in the entire country and regularly exceed the average salary in coal mining areas.

5. Coal is America's most abundant energy resource—making up 85 percent of U.S. fossil energy reserves on a Btu basis. With increased electrification and surging power demand, and as our economy

[2] U.S. Dep't Interior., U.S. Geological Survey, *Mineral Commodity Summaries 2024* 9 tbl.1 (2024), https://pubs.usgs.gov/periodicals/mcs2024/mcs2024.pdf.

and population expand, our need for electricity will continue to grow. Coal is a workhorse fuel for power generation, providing 670.7 billion kilowatt hours of electricity, which calculates to nearly 17 percent of the Nation's electricity net power sector generation, in 2023.[3] Coal provides affordable and reliable baseload power to households, businesses, manufacturing facilities, transportation and communication systems, and services throughout our economy. Coal will continue to be called upon to meet the Nation's power needs even assuming ambitious growth scenarios are met for electricity generation from renewables and natural gas energy sources. Coal is also an affordable source of energy. Electricity costs are generally lower in States that rely upon coal for their electricity generation versus States that rely on other fuels. In 2020, 34 million Americans—27 percent of the population—were considered energy insecure. Dispatchable baseload power from coal that is reliable and affordable is critical to maintaining a healthy, safe, and modern standard of living.

[3] EIA, *Monthly Energy Review* (Apr. 2024) (Table 7.2b: Electricity Net Generation: Electric Power Sector), https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

6. I am familiar with the preparation and submission of the NMA's comments on EPA's Proposed Rule and the impacts the Final Rule will have on NMA members.[4] Nothing in the Final Rule alleviates the NMA's concern that EPA has failed to demonstrate that its new standards for filterable particulate matter ("fPM") and mercury are achievable, particularly by lignite-powered electric generating units ("EGUs").

7. I am familiar with the declarations filed by NACCO NR Natural Resources Corporation ("NACCO NR"), Lignite Energy Council ("LEC"), and Mike Holmes. NACCO NR and LEC are members of the NMA, and Mike Holmes is LEC's Vice President. As NACCO NR explained, the changes required by MATS, both in the fPM and mercury standards, are likely not technologically feasible for lignite-based power generation facilities. NACCO NR Decl. ¶ 5; *see also* NMA Comments, *supra*, at 10–12 (fPM standard) and 14–16 (mercury standard). LEC also demonstrates the technological and practical difficulties of achieving compliance. LEC Decl. ¶¶ 21–23. EPA has also significantly

[4] *See, e.g.*, Comment from Tawny A. Bridgeford, National Mining Association (June 23, 2023), Doc. ID No. EPA-HQ-OAR-2018-0794-5986 (comments on Proposed Rule) (hereinafter, "NMA Comments").

underestimated the costs and timeframe necessary even to attempt comply, as well as impacts to the power grid. *See* NACCO NR Decl. ¶¶ 29–30; *id.* Attach. A at 24–27, 31–37; Mike Holmes Decl. ¶¶ 5, 8(a), 10; LEC Decl. ¶¶ 19–27; NMA Comments at 9.[5] The only alternative to compliance is to prematurely retire coal plants. *See* NACCO NR Decl. Attach. A at 3, 25, 31–33; LEC Decl. ¶ 24.

8. Accordingly, unless it is stayed, the Final Rule will inflict immediate and irreparable harm on coal-fired generators, some of which will be forced to retire prematurely due to their inability to achieve compliance. *See* NACCO NR Decl. ¶¶ 5 & 30 & Attach. A at 3, 25, 31–33. They will not be able to unwind this decision if the Court finds the Final Rule unlawful, nor recover the resulting hundreds of millions of dollars of stranded assets. *See id.* ¶¶ 5, 9, 17, & 28. By extension, these harms on generating facilities will inevitably harm NMA members—namely, coal producers that supply coal-fired EGUs—whose fates are inextricably

[5] Citing J. Edward Cichanowicz, *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 16-21 (June 2023) (prepared on behalf of the National Rural Electric Cooperative Association, American Public Power Association, America's Power, Midwest Ozone Group, NAACO, National Mining Association, and Power Generators Air Coalition) ("Cichanowicz Report").

linked to the coal-fired power sector and who depend on a stable and continued domestic coal market.

9. As NMA member LEC explains, North Dakota lignite mining operations will be particularly hard-hit. In North Dakota, lignite coal is mined on a mine-to-mouth model, with each EGU contracting with a nearby lignite mine for its supply of lignite. LEC Decl. ¶ 10. The closure of a lignite EGU as a result of the Final Rule would mean the closure of the mine that supplies it, which will have no reasonable or viable market alternative. *Id.*

10. Similarly, NMA member NACCO NR has attested that the Final Rule will significantly affect several lignite-fired EGUs, including the Red Hills Generating Facility, Antelope Valley Station, Coal Creek Station, Coyote Station, Leland Olds, and Spiritwood Station, and EPA's own estimates confirm this conclusion. NACCO NR Decl. ¶ 5. Because these facilities all purchase lignite coal from NACCO NR, the closure of these facilities would force the closure of the mines that supply them, at a loss of tens of millions of investment dollars and a substantial number of jobs. *Id.*

11. Moreover, nothing in the Final Rule alleviates NMA's concerns, articulated during the comment period, about the Rule's impact on grid reliability. *See* NMA Comments, *supra*, at 18–24. With the Final Rule, EPA has continued its pattern of ignoring the alarms raised by grid experts concerning the threats to grid reliability resulting from rapid early retirement of dispatchable resources. EPA's Final Rule will accelerate the forced retirement of needed coal plants and exacerbate the reliability crisis. *See* NACCO NR Decl. ¶¶ 5; *id.* Attach. A at 3, 24–25, 27–32; LEC Decl. ¶¶ 7. Absent a stay, the EGU and mine closures necessitated by the Final Rule will be irreversible by the time the Court can rule on the Final Rule's lawfulness, leaving power-vulnerable communities that rely on lignite-fueled energy at even greater risk of being left in the dark.

12. I, Tawny Bridgeford, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Executed on June 11, 2024, in Washington, DC.

Tawny Bridgeford

Exhibit 9

DECLARATION OF JASON BOHRER

I, Jason Bohrer, declare as follows:

1. I am over eighteen years of age, suffer from no disability that would preclude me from giving this declaration, and make this declaration based upon personal knowledge or information available to me in the performance of my professional duties.

2. I am President and Chief Executive Officer of the Lignite Energy Council (LEC).

3. I have been employed by the LEC for 11 years and held my current title for that entire time. My responsibilities include directing and coordinating the policy work and research and development priorities of the LEC.

4. The LEC is a trade association that represents various lignite mines, lignite-fired power plants and conversion facilities, as well as the businesses that contribute goods and services to the industry. Its members produce electricity and also gasify lignite coal, which is then turned into synthetic natural gas and other valuable byproducts.

5. LEC members provide electricity to two Regional Transmission Organizations: the Midcontinent Independent Systems Operator and the Southwest Power Pool.

6. I am providing this declaration in support of the motion to stay the rule promulgated by the U.S. Environmental Protection Agency ("EPA") entitled *National*

Emission Standards for Hazardous Air Pollutants: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38,508 (May 7, 2024) ("MATS RTR").

7. The MATS RTR threatens the viability of North Dakota's lignite-fired power plants and coal mines. The MATS RTR also endangers the reliability and resilience of the power grids in North Dakota and the surrounding regions.

8. LEC members have extensive experience in operating electric generating units (EGUs) powered by lignite coal while using a variety of emission control technologies.

9. North Dakota contains the world's largest deposit of lignite coal. Lignite coal is a geologically young form of coal and lacks the homogeneity found in older types of coal.

10. In North Dakota, lignite coal is mined adjacent to the EGUs and conversion facilities where it is used in a "mine-to-mouth" operation. Each EGU contracts with an individual lignite mine for its supply of lignite, and these EGUs have been geographically sited based on the availability of lignite coal. Neither market economics nor coal transportation logistics allow for fuel switching or coal blending. Should an associated lignite EGU close, the mine providing coal for it would have no reasonable or viable market alternative.

11. The total number of EGU employees in North Dakota is 7,725, and the total number of mining jobs is 3,250. This ratio suggests that for each employee at a mine there are two employees at a power plant.

12. Emission control solutions are not interchangeable and are crafted on an EGU-by-EGU basis due to the differences in coal composition, power plant technology and operational needs at each facility.

13. Particularly for lignite-firing EGUs, the variability in chemical composition of lignite coal, along with mine-to-mouth operations, requires that EGUs maintain an emission control compliance margin that accounts for variability in coal composition and required operational conditions.

14. The lignite subcategory created by the EPA in the 2012 MATS rule reflected the reality that the chemical makeup and characteristics of lignite not only cause different emissions profiles than bituminous or sub-bituminous coals, but also reflect the lower homogeneity of lignite coal compared to other types of coal.

15. The lignite subcategory therefore reflected basic chemical truths, such as the mechanism by which the higher sulfur content of lignite reduces the effectiveness of sorbent mercury reduction solutions and the interplay between the formation of SO3 and potential mercury reduction technologies.

16. LEC is not currently aware of any verified or demonstrated technology that will consistently allow all of North Dakota's lignite-firing EGUs to comply with the MATS RTR's newly lowered Hg requirement of 1.2 lb/TBtu.

17. Illustrating that point, testing performed by LEC member Minnkota Power Cooperative verified that the increased utilization of sorbents, even at significantly elevated levels, would not result in consistent compliance with the newly reduced Hg limit.

The new limit will cause immediate and irreparable harm to LEC Members.

18. LEC's members are actively trying to determine if they will be able to comply with the MATS RTR's reduced emission requirements and still remain commercially viable. Testing alone to accurately quantify the requirements specific to each unique EGU is estimated at more than $1,000,000.00 per unit.

19. Even if such further testing indicated the new emission limitations could be met (and it is not currently clear that they could be), the construction costs necessary to update or replace existing technologies and optimize operation would be expensive and time consuming.

20. New expenses would be added to those one-time construction expenditures (estimated at a minimum of $5,000,000.00 by Minnkota Power Cooperative for a single facility) by requiring additional sorbents or other

control materials. These new expenses would continue in perpetuity along with increased operating costs.

21. Each EGU in North Dakota is unique, but they share in the difficulty of establishing the feasibility of a path to compliance, and, if one is achievable, the expenses incurred in implementation, as well as the continual ongoing costs. For example, a baghouse is estimated to cost $282,715 per fPM ton removed while an ESP retrofit is estimated at $67,262 per fPM ton removed. Operators will be forced to pass along those costs to ratepayers or other end users to continue to operate.

22. Moreover, should feasibility testing indicate compliance is possible, the substantial modifications required by the MATS RTR would need to be implemented immediately.

23. For example, electrostatic precipitator upgrades carry a three-year timeline from start of construction to implementation. For the EPA's assessment to be accurate that no facilities will close due to the MATS RTR, at least 26 impacted EGUs in the country would be competing for the 4 vendors capable of performing the work. And based on historical performance, it is unlikely the four contractors could perform the work needed for all 26 plants in that 3-year period.

24. The alternative to compliance is to shut down or operate at such a reduced level that end of life will occur prematurely for the EGU. For every two jobs

lost at a power plant due to premature shut down, a worker in a lignite mine who will also lose their job.

<u>The MATS RTR Rule will harm North Dakotans</u>

25. The elimination of the lignite subcategory will impact North Dakota and North Dakotans in multiple ways. Lignite provides most of the electricity consumed in North Dakota, and it provides the backbone of reliability and resilience.

26. Should testing indicate compliance with the MATS RTR's new emission limits is possible for every EGU in North Dakota, the implementation of new control technologies at each EGU would require multiple EGUs be taken offline for extended periods of time, concentrating the danger of an unstable, unreliable grid on North Dakota and its residents.

27. As a recent study commissioned by the North Dakota Transmission Authority confirmed, the power grids serving the people of North Dakota are already operating on dangerously thin margins of dispatchable power. Available at https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/ Publications/MATS_Analysis_Report.pdf. Consequently, even if Noth Dakota plants are capable of complying with the MATS RTR's new standards (which, as noted above, remains entirely uncertain), complying with the Rule would require taking multiple units offline for an extended duration to make necessary upgrades, removing load from power grids that are not projected to have capacity to spare.

28. Winters in North Dakota require consistently available power for homes, hospitals and businesses to provide care and services for families. Previous blackouts in other parts of the country associated with Winter Storm Uri have demonstrated that death and health impacts can follow blackouts even in relatively mild weather.

29. Consequently, the MATS RTR will impose significant regulatory burdens and cost on coal-fired EGUs in North Dakota and create serious risks to the health and welfare of people in the region.

30. I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed this 3rd day of June 2024.

Jason Bohrer
President and Chief Executive Officer
Lignite Energy Council

Exhibit 10

DECLARATION OF RUSSELL RAAD, PRESIDENT OF ABRASIVES, INC.

I, Russell Raad, declare as follows:

1. My name is Russell Raad, and I am the President of Abrasives, Inc. ("Abrasives").

2. Abrasives is the manufacturer of Black Magic Coal Slag, a low-dusting, CARB- and QPL-approved blasting material made from the recycled by-product of power plants. Media blasting is a non-toxic, non-destructive method used in a wide range of industries for preparing surfaces for painting, priming, welding, and other operations. In addition to blast media, Abrasives offers high quality equipment and products such as protective gear, personal monitors, coatings and painting equipment.

3. Abrasives is proudly employee-owned and headquartered in North Dakota, with offices and warehouses in central Minnesota, western Texas and eastern New Mexico, and throughout the West and Midwest. Currently valued at $25 million, Abrasives currently employs forty-seven individuals.

4. The EPA Final Rule will immediately harm Abrasives by stigmatizing the raw material—coal slag—that is essential to the manufacture of our flagship product. EPA's decision to make its hazardous air pollutant standards more stringent suggests that the environmental impact of coal-fired is much greater than EPA's own analysis shows. In fact, EPA's modeling confirms that the maximum level of risk associated with hazardous air pollutant emissions from any coal fired power plants is less than

EPA's presumptive level of acceptability and even less than the threshold Congress identified as the level at which a source category could be removed from the program.

5. The negative public perception directly resulting from EPA's final rule will cause an immediate decline in our share price. Current projections show that Abrasives' share price will drop immediately by an estimated minimum of 20 percent as a result of the negative light the new rule will cast on our products and services, immediately diminishing the value of our employee-owners' shares by a combined $4 million.

6. In addition, over the next twelve and no later than twenty-four months, EPA's final rule will force coal-powered generators to make irrevocable decisions about whether to retire their generating units or whether to change their emission control strategies. In either case, Abrasives will be harmed—the permanent shutdown of the facilities that produce the input to Abrasives primary product could devastate the business model, and, even without a shutdown, a change in control strategy could alter the nature of the coal slag produced, through the injection of additional chemicals in an attempt to meet the new mercury standard.

7. Given the inevitable effects of either permanent shutdowns or significantly altering in the chemical makeup of the coal slag produced by the facilities that enable Abrasives to conduct its primary business, Abrasives will be forced either to close or to radically change its business strategy, which may include changes to personnel and investments in continued operations.

8. For example, Minnkota has acknowledged that inability to comply with the Final Rule will force some units to retire. Minnkota Decl. ¶ 62. Abrasives currently removes 150,000 tons of coal slag per year from two Minnkota stations—a raw material that is essential to the production of our core products.

9. Early retirements at these Minnkota facilities would deprive Abrasives of this essential raw material. If Abrasives were to survive this loss of supply at all—a prospect that is far from certain—Abrasives would be forced immediately to eliminate between 15 and 25 jobs, and immediately to mothball costly heavy equipment that is currently used for drying and screening. That equipment would become essentially worthless, because it is specifically designed to be used with this particular raw material. Moreover, it could not be brought back online without significant additional expense if the Court ultimately invalidates the Final Rule.

10. In addition, Abrasives would be unable to continue to pay either our current property costs, which total approximately a half-million dollars per year, and would substantially reduce Abrasives' annual local, state, and federal tax contributions, which now total the $1.2 million.

11. The Final Rule's impact on Abrasives will also have downstream impacts on its customers by reducing or eliminating access to products they rely on, and it will also harm Abrasives' workers, their families, and their communities.

12. I, Russell Raad, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Russell Raad
Abrasives, Inc.

Dated: June 7, 2024

Exhibit 11

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR]

RIN 2060–AV53

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) for the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs) source category. These final amendments are the result of the EPA's review of the 2020 Residual Risk and Technology Review (RTR). The changes, which were proposed under the technology review in April 2023, include amending the filterable particulate matter (fPM) surrogate emission standard for non-mercury metal hazardous air pollutants (HAP) for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, and the mercury (Hg) emission standard for lignite-fired EGUs. Additionally, the EPA is finalizing a change to the definition of ''startup.'' The EPA did not propose, and is not finalizing, any changes to the 2020 Residual Risk Review.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain material listed in the rule was approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The U.S. Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0794. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *https://www.regulations.gov,* or in hard copy at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action contact Sarah Benish, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5620; and email address: *benish.sarah@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

APH air preheater
Btu British Thermal Units
CAA Clean Air Act
CEMS continuous emission monitoring system
EGU electric utility steam generating unit
EIA Energy Information Administration
ESP electrostatic precipitator
FF fabric filter
FGD flue gas desulfurization
fPM filterable particulate matter
GWh gigawatt-hour
HAP hazardous air pollutant(s)
HCl hydrogen chloride
HF hydrogen fluoride
Hg mercury
Hg^0 elemental Hg vapor
Hg^{2+} divalent Hg
$HgCl_2$ mercuric chloride
Hg_p particulate bound Hg
HQ hazard quotient
ICR Information Collection Request
IGCC integrated gasification combined cycle
IPM Integrated Planning Model
IRA Inflation Reduction Act
lb pounds
LEE low emitting EGU
MACT maximum achievable control technology
MATS Mercury and Air Toxics Standards
MMacf million actual cubic feet
MMBtu million British thermal units of heat input
MW megawatt
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NO_X nitrogen oxides
NRECA National Rural Electric Cooperative Association
OMB Office of Management and Budget
PM particulate matter
$PM_{2.5}$ fine particulate matter
PM CEMS particulate matter continuous emission monitoring systems
REL reference exposure level
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RIN Regulatory Information Number
RTR residual risk and technology review
SC–CO_2 social cost of carbon
SO_2 sulfur dioxide
TBtu trillion British thermal units of heat input
tpy tons per year
UMRA Unfunded Mandates Reform Act
WebFIRE Web Factor Information Retrieval System

Background information. On April 24, 2023, the EPA proposed revisions to the Coal- and Oil-Fired EGU NESHAP based on our review of the 2020 RTR. In this action, we are finalizing revisions to the rule, commonly known as the Mercury and Air Toxics Standards (MATS). We summarize some of the more significant comments regarding the proposed rule that were received during the public comment period and provide our responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* Docket ID No. EPA–HQ–OAR–2018–0794. A ''track changes'' version of the regulatory language that incorporates the changes in this action is available in the docket.

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Background and Purpose of the Regulatory Action

Exposure to hazardous air pollutants (''HAP,'' sometimes known as toxic air pollution, including Hg, chromium, arsenic, and lead) can cause a range of adverse health effects including harming people's central nervous system; damage to their kidneys; and cancer. These adverse effects can be particularly acute for communities living near sources of HAP. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, the EPA is required to set standards based on maximum achievable control technology (known as ''MACT'' standards) for major sources [1] of HAP that ''require the maximum degree of reduction in emissions of the hazardous air pollutants . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable.'' 42 U.S.C. 7412(d)(2). The EPA is further required to ''review, and revise'' those standards every 8 years ''as necessary (taking into account developments in practices, processes, and control technologies).'' *Id.* 7412(d)(6).

On January 20, 2021, President Biden signed Executive Order 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis'' (86 FR 7037; January 25, 2021). The executive order, among other things, instructed the EPA to review the 2020 final rule titled *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil- Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review* (85 FR 31286; May 22, 2020) (2020 Final Action) and to consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action. The 2020 Final Action included two parts: (1) a finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112; and (2) the RTR for the 2012 MATS Final Rule.

The EPA reviewed both parts of the 2020 Final Action. The results of the EPA's review of the first part, finding it is appropriate and necessary to regulate EGUs under CAA section 112, were proposed on February 9, 2022 (87 FR 7624) (2022 Proposal) and finalized on March 6, 2023 (88 FR 13956). In the 2022 Proposal, the EPA also solicited information on the performance and cost of new or improved technologies that control HAP emissions, improved methods of operation, and risk-related information to further inform the EPA's review of the second part, the 2020 MATS RTR. The EPA proposed amendments to the RTR on April 24, 2023 (88 FR 24854) (2023 Proposal) and this action finalizes those amendments and presents the final results of the EPA's review of the MATS RTR.

2. Summary of Major Provisions of the Regulatory Action

Coal- and oil-fired EGUs remain one of the largest domestic emitters of Hg and many other HAP, including many of the non-Hg HAP metals—including lead, arsenic, chromium, nickel, and cadmium—and hydrogen chloride (HCl). Exposure to these HAP, at certain levels and duration, is associated with a variety of adverse health effects. In the 2012 MATS Final Rule, the EPA established numerical standards for Hg, non-Hg HAP metals, and acid gas HAP emissions from coal- and oil-fired EGUs. The EPA also established work practice standards for emissions of organic HAP. To address emissions of non-Hg HAP

[1] The term ''major source'' means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. 42 U.S.C. 7412(a)(1).

metals, the EPA established individual emission limits for each of the 10 non-Hg HAP metals [2] emitted from coal- and oil- fired EGUs. Alternatively, affected sources could meet an emission standard for ''total non-Hg HAP metals'' by summing the emission rates of each of the non-Hg HAP metals or meet a fPM emission standard as a surrogate for the non-Hg HAP metals. For existing coal-fired EGUs, almost every unit has chosen to demonstrate compliance with the non-Hg HAP metals surrogate fPM emission standard of 0.030 pounds (lb) of fPM per million British thermal units of heat input (lb/MMBtu).

Pursuant to CAA section 112(d)(6), the EPA reviewed developments in the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a fPM emission standard that is more stringent than 0.030 lb/MMBtu and the other statutory factors. Based on that review, the EPA is finalizing, as proposed, a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu. This strengthened standard will ensure that the entire fleet of coal-fired EGUs is performing at the fPM pollution control levels currently achieved by the vast majority of regulated units. The EPA further concludes that it is the lowest level currently compatible with the use of PM CEMS for demonstrating compliance.

Relatedly, the EPA is also finalizing a revision to the requirements for demonstrating compliance with the revised fPM emission standard. Currently, affected EGUs that do not qualify for the low emitting EGU (LEE) program for fPM [3] can demonstrate compliance with the fPM standard either by conducting quarterly performance testing (*i.e.,* quarterly stack testing) or by using particulate matter (PM) continuous emission monitoring systems (PM CEMS). PM CEMS confer significant benefits, including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. After considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and the measurement capabilities of PM CEMS, as well as the many benefits of using PM CEMS, the EPA is finalizing, as proposed, a requirement that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. As the EPA explained in the 2023 Proposal, by requiring facilities to use PM CEMS, the current compliance method for the LEE program becomes superfluous since LEE is an optional program in which stack testing occurs infrequently, and the revised fPM limit is below the current fPM LEE program limit. Therefore, the EPA is finalizing, as proposed, the removal of the fPM LEE program.

Based on comments received during the public comment period, the EPA is not removing, but instead revising the alternative emission limits for the individual non-Hg HAP metals such as lead, arsenic, chromium, nickel, and cadmium and for the total non-Hg HAP metals proportional to the finalized fPM emission limit of 0.010 lb/MMBtu.[4] Owners and operators of EGUs seeking to use these alternative standards must request and receive approval to use a HAP metal continuous monitoring system (CMS) as an alternative test method under 40 CFR 63.7(f).

The EPA is also finalizing, as proposed, a more protective Hg emission standard for existing lignite-fired EGUs, requiring that such lignite-fired EGUs meet the same Hg emission standard as EGUs firing other types of coal (*i.e.,* bituminous and subbituminous), which is 1.2 lb of Hg per trillion British thermal units of heat input (lb/TBtu) or an alternative output-based standard of 0.013 lb per gigawatt-hour (lb/GWh). Finally, the EPA is finalizing, as proposed, the removal of the second option for defining the startup period for MATS-affected EGUs.

The EPA did not propose and is not finalizing modifications to the HCl emission standard (nor the alternative sulfur dioxide (SO_2) emission standard), which serves as a surrogate for all acid gas HAP (HCl, hydrogen fluoride (HF), selenium dioxide (SeO_2)) for existing coal-fired EGUs. The EPA proposed to require PM CEMS for existing integrated gasification combined cycle (IGCC) EGUs but is not finalizing this requirement due to technical issues calibrating CEMS on these types of EGUs and the related fact that fPM emissions from IGCCs are very low.

In establishing the final standards, as discussed in detail in sections IV., V., VI., and VII. of this preamble, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112. Separately, pursuant to Executive Order 12866 and Executive Order 14904, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is available in the docket, and is briefly summarized in sections I.A.3. and IX. of this preamble.

3. Costs and Benefits

In accordance with Executive Order 12866 and 14094, the EPA prepared a Regulatory Impact Analysis (RIA). The RIA presents estimates of the emission, cost, and benefit impacts of this final rulemaking for the 2028 to 2037 period; those estimates are summarized in this section.

The power industry's compliance costs are represented in the RIA as the projected change in electric power generation costs between the baseline and final rule scenarios. The quantified emission estimates presented in the RIA include changes in pollutants directly covered by this rule, such as Hg and non-Hg HAP metals, and changes in other pollutants emitted from the power sector due to the compliance actions projected under this final rule. The cumulative projected national-level emissions reductions over the 2028 to 2037 period under the finalized requirements are presented in table 1. The supporting details for these estimates can be found in the RIA.

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[2] The ten non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[3] In order to qualify for fPM LEE status, an EGU must demonstrate that its fPM emission rate is below 50 percent of standard (or 0.015 lb/MMBtu) from quarterly stack tests for 3 consecutive years. Once a source achieves LEE status for fPM, the source must conduct stack testing every 3 years to demonstrate that its emission rate remains below 50 percent of the standard.

[4] The emission limits for the individual non-Hg HAP metals and the total non-Hg HAP metals have been reduced by two-thirds, consistent with the revision of the fPM emission limit from 0.030 lb/MMBtu to 0.010 lb/MMBtu.

Table 1. Cumulative Projected Emissions Reductions under the Final Rule, 2028 to 2037[a]

Pollutant	Emissions Reductions
Hg (pounds)	9,500
$PM_{2.5}$ (tons)	5,400
SO_2 (tons)	770
NO_x (tons)	220
CO_2 (thousand tons)	650
non-Hg HAP metals (tons)[b]	49

[a] Values rounded to two significant figures.

[b] The non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

The EPA expects that emission reductions under the final rulemaking will result in reduced exposure to Hg and non-Hg HAP metals. The EPA also projects health benefits due to improvements in particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$) and ozone and climate benefits from reductions in carbon dioxide (CO_2) emissions. The EPA also anticipates benefits from the increased transparency to the public, the assurance that standards are being met continuously, and the accelerated identification of anomalous emissions due to requiring PM CEMS in this final rule.

The EPA estimates negative net monetized benefits of this rule (see table 2 below). However, the benefit estimates informing this result represent only a partial accounting of the potential benefits of this final rule. Several categories of human welfare and climate benefits are unmonetized and are thus not directly reflected in the quantified net benefit estimates (see section IX.B. in this preamble and section 4 of the RIA for more details). In particular, estimating the economic benefits of reduced exposure to HAP generally has proven difficult for a number of reasons: it is difficult to undertake epidemiologic studies that have sufficient power to quantify the risks associated with HAP exposures experienced by U.S. populations on a daily basis; data used to estimate exposures in critical microenvironments are limited; and there remains insufficient economic research to support valuation of HAP benefits made even more challenging by the wide array of HAP and possible HAP effects.[5] In addition, due to data limitations, the EPA is also unable to quantify potential emissions impacts or monetize potential benefits from continuous monitoring requirements.

The present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this rulemaking over the 2028 to 2037 period in 2019 dollars are shown in table 2. In this table, results are presented using a 2 percent discount rate. Results under other discount rates and supporting details for the estimates can be found in the RIA.

[5] See section II.B.2. for discussion of the public health and environmental hazards associated with HAP emissions from coal- and oil-fired EGUs and discussion on the limitations to monetizing and quantifying benefits from HAP reductions. See also *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023).

Table 2. Projected Benefits, Costs, and Net Benefits under the Final Rule, 2028 to 2037 (millions of 2019 dollars, discounted to 2023)[a]

	2% Discount Rate	
	PV	EAV
Ozone- and $PM_{2.5}$-related Health Benefits	300	33
Climate Benefits[b]	130	14
Compliance Costs	860	96
Net Benefits[c]	-440	-49
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually	
	Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually	
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate.

[c] Several categories of benefits remain unmonetized and are thus not reflected in the table.

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The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discusses in section II.A. and sections IV. through VII. below.

B. Does this action apply to me?

Regulated entities. The source category that is the subject of this action is coal- and oil-fired EGUs regulated by NESHAP under 40 CFR part 63, subpart UUUUU, commonly known as MATS. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU source category are 221112, 221122, and 921150. This list of NAICS codes is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will also be available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at: *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same website.

Additional information is available on the RTR website at *https://www.epa.gov/stationary-sources-air-pollution/risk-and-technology-review-national-emissions-standards-hazardous.* This information includes an overview of the RTR program and links to project websites for the RTR source categories.

D. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by July 8, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure that was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave., NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate

General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. Statutory Language

The statutory authority for this action is provided by sections 112 and 301 of the CAA, as amended (42 U.S.C. 7401 *et seq.*). Section 112 of the CAA establishes a multi-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, during the first stage, Congress directed the EPA to establish technology-based standards to ensure that all major sources control HAP emissions at the level achieved by the best-performing sources, referred to as the MACT. After the first stage, Congress directed the EPA to review those standards periodically to determine whether they should be strengthened. Within 8 years after promulgation of the standards, the EPA must evaluate the MACT standards to determine whether the emission standards should be revised to address any remaining risk associated with HAP emissions. This second stage is commonly referred to as the ''residual risk review.'' In addition, the CAA also requires the EPA to review standards set under CAA section 112 on an ongoing basis no less than every 8 years and revise the standards as necessary taking into account any ''developments in practices, processes, and control technologies.'' This review is commonly referred to as the ''technology review,'' and is the primary subject of this final rule. The discussion that follows identifies the most relevant statutory sections and briefly explains the contours of the methodology used to implement these statutory requirements.

In the first stage of the CAA section 112 standard-setting process, the EPA promulgates technology-based standards under CAA section 112(d) for categories of sources identified as emitting one or more of the HAP listed in CAA section 112(b). Sources of HAP emissions are either major sources or area sources, and CAA section 112 establishes different requirements for major source standards and area source standards. ''Major sources'' are those that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. All other sources are ''area sources.'' For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect ''*the maximum degree of reduction* in emissions of the [HAP] subject to this section (*including a prohibition on such emissions, where achievable*) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable.'' (emphasis added). These standards are commonly referred to as MACT standards. CAA section 112(d)(3) establishes a minimum control level for MACT standards, known as the MACT ''floor.'' [6] In certain instances, as provided in CAA section 112(h), the EPA may set work practice standards in lieu of numerical emission standards. The EPA must also consider control options that are more stringent than the floor. Standards more stringent than the floor are commonly referred to as ''beyond-the-floor'' standards. For area sources, CAA section 112(d)(5) allows the EPA to set standards based on generally available control technologies or management practices (GACT standards) in lieu of MACT standards.[7]

For categories of major sources and any area source categories subject to MACT standards, the next stage in standard-setting focuses on identifying and addressing any remaining (*i.e.,* ''residual'') risk pursuant to CAA section 112(f)(2). The residual risk review requires the EPA to update standards if needed to provide an ample margin of safety to protect public health.

Concurrent with that review, and then at least every 8 years thereafter, CAA section 112(d)(6) requires the EPA to review standards promulgated under CAA section 112 and revise them ''as necessary (taking into account developments in practices, processes, and control technologies).'' *See Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 189 (D.C. Cir. 2011) (''Though EPA must review and revise standards 'no less often than every eight years,' 42 U.S.C. 7412(d)(6), nothing prohibits EPA from reassessing its standards more often.''). In conducting this review, which we call the ''technology review,'' the EPA is not required to recalculate the MACT floors that were established in earlier rulemakings. *Natural Resources Defense Council (NRDC)* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008); *Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). *See e.g., Nat'l Ass'n for Surface Finishing,* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA is required to address regulatory gaps, such as missing MACT standards for listed air toxics known to be emitted from the source category. *Louisiana Environmental Action Network (LEAN)* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020). The residual risk review and the technology review are distinct requirements and are both mandatory.

In this action, the EPA is finalizing amendments to the MACT standards based on two independent sources of authority: (1) its review of the 2020 Final Action's risk and technology review pursuant to the EPA's statutory authority under CAA section 112, and (2) the EPA's inherent authority to reconsider previous decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *see also Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983).

2. Statutory Structure and Legislative History

In addition to the text of the specific subsections of CAA section 112 discussed above, the statutory structure and legislative history of CAA section 112 further support the EPA's authority to take this action. Throughout CAA section 112 and its legislative history, Congress made clear its intent to quickly secure large reductions in the volume of HAP emissions from stationary sources based on technological developments in control technologies because of its recognition of the hazards to public health and the environment that result from exposure to such emissions. CAA section 112 and its legislative history also reveal Congress's understanding that fully characterizing the risks posed by HAP emissions was exceedingly difficult. Thus, Congress purposefully replaced a regime that required the EPA to make an assessment of risk in the first instance, with one in which Congress determined risk existed and directed the EPA to make swift and substantial reductions based upon the most stringent standards technology could achieve.

Specifically, in 1990, Congress radically transformed section 112 of the CAA and its treatment of HAP through the Clean Air Act Amendments, by

[6] Specifically, for existing sources, the MACT ''floor'' shall not be less stringent than the average emission reduction achieved by the best performing 12 percent of existing sources. 42 U.S.C. 7412(d)(3). For new sources MACT shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source. *Id.*

[7] For categories of area sources subject to GACT standards, there is no requirement to address residual risk, but, similar to the major source categories, the technology review is required.

amending CAA section 112 to be a technology-driven standard setting provision as opposed to the risk-based one that Congress initially promulgated in the 1970 CAA. The legislative history of the 1990 Amendments indicates Congress's dissatisfaction with the EPA's slow pace addressing HAP under the 1970 CAA: ''In theory, [hazardous air pollutants] were to be stringently controlled under the existing Clean Air Act section 112. However, . . . only 7 of the hundreds of potentially hazardous air pollutants have been regulated by EPA since section 112 was enacted in 1970.'' H.R. Rep. No. 101–490, at 315 (1990); see also *id.* at 151 (noting that in 20 years, the EPA's establishment of standards for only seven HAP covered ''a small fraction of the many substances associated . . . with cancer, birth defects, neurological damage, or other serious health impacts.'').

In enacting the 1990 Amendments with respect to the control of HAP, Congress noted that ''[p]ollutants controlled under [section 112] tend to be less widespread than those regulated [under other sections of the CAA], but are often associated with more serious health impacts, such as cancer, neurological disorders, and reproductive dysfunctions.'' *Id.* at 315. In its substantial 1990 Amendments, Congress itself listed 189 HAP (CAA section 112(b)) and set forth a statutory structure that would ensure swift regulation of a significant majority of these HAP emissions from stationary sources. Specifically, after defining major and area sources and requiring the EPA to list all major sources and many area sources of the listed pollutants (CAA section 112(c)), the new CAA section 112 required the EPA to establish technology-based emission standards for listed source categories on a prompt schedule and to revisit those technology-based standards every 8 years on an ongoing basis (CAA section 112(d) (emission standards); CAA section 112(e) (schedule for standards and review)). The 1990 Amendments also obligated the EPA to conduct a one-time evaluation of the residual risk within 8 years of promulgation of technology-based standards. CAA section 112(f)(2).

In setting the standards, CAA section 112(d) requires the EPA to establish technology-based standards that achieve the ''maximum degree of reduction,'' ''including a prohibition on such emissions where achievable.'' CAA section 112(d)(2). Congress specified that the maximum degree of reduction must be at least as stringent as the average level of control achieved in practice by the best performing sources in the category or subcategory based on emissions data available to the EPA at the time of promulgation. This technology-based approach enabled the EPA to swiftly set standards for source categories without determining the risk or cost in each specific case, as the EPA had done prior to the 1990 Amendments. In other words, this approach to regulation quickly required that all major sources and many area sources of HAP meet an emission standard consistent with the top performers in each category, which had the effect of obtaining immediate reductions in the volume of HAP emissions from stationary sources. The statutory requirement that sources obtain levels of emission limitation that have actually been achieved by existing sources, instead of levels that could theoretically be achieved, inherently reflects a built-in cost consideration.[8]

Further, after determining the minimum stringency level of control, or MACT floor, CAA section 112(d)(2) directs the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable)'' that the EPA determines are achievable after considering the cost of achieving such standards and any non-air-quality health and environmental impacts and energy requirements of additional control. In doing so, the statute further specifies in CAA section 112(d)(2) that the EPA should consider requiring sources to apply measures that, among other things, ''reduce the volume of, or eliminate emissions of, such pollutants . . . '' (CAA section 112(d)(2)(A)), ''enclose systems or processes to eliminate emissions'' (CAA section 112(d)(2)(B)), and ''collect, capture, or treat such pollutants when released . . . '' (CAA section 112(d)(2)(C)). The 1990 Amendments also built in a regular review of new technologies and a one-time review of risks that remain after imposition of MACT standards. CAA section 112(d)(6) requires the EPA to evaluate every NESHAP no less often than every 8 years to determine whether additional control is necessary after taking into consideration ''developments in practices, processes, and control technologies,'' separate from its obligation to review residual risk. CAA section 112(f) requires the EPA to ensure within 8 years of promulgating a NESHAP that the risks are acceptable and that the MACT standards provide an ample margin of safety.

The statutory requirement to establish technology-based standards under CAA section 112 eliminated the requirement for the EPA to identify hazards to public health and the environment in order to justify regulation of HAP emissions from stationary sources, reflecting Congress's judgment that such emissions are inherently dangerous. See S. Rep. No. 101–228, at 148 (''The MACT standards are based on the performance of technology, and not on the health and environmental effects of the [HAP].''). The technology review required in CAA section 112(d)(6) further mandates that the EPA continually reassess standards to determine if additional reductions can be obtained, without evaluating the specific risk associated with the HAP emissions that would be reduced. Notably, Congress required the EPA to conduct the CAA section 112(d)(6) review of what additional reductions may be obtained based on new technology even after the EPA has conducted the one-time CAA section 112(f)(2) risk review and determined that the existing standard will protect the public with an ample margin of safety. The two requirements are distinct, and both are mandatory.

B. What is the Coal- and Oil-Fired EGU source category and how does the NESHAP regulate HAP emissions from the source category?

1. Summary of Coal- and Oil-Fired EGU Source Category and NESHAP Regulations

The EPA promulgated the Coal- and Oil-Fired EGU NESHAP (commonly referred to as MATS) on February 16, 2012 (77 FR 9304) (2012 MATS Final Rule). The standards are codified at 40 CFR part 63, subpart UUUUU. The coal- and oil-fired electric utility industry consists of facilities that burn coal or oil located at both major and area sources of HAP emissions. An existing affected source is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began

[8] Congress recognized as much: ''The Administrator may take the cost of achieving the maximum emission reduction and any non-air quality health and environmental impacts and energy requirements into account when determining the emissions limitation which is achievable for the sources in the category or subcategory. Cost considerations are reflected in the selection of emissions limitations which have been achieved in practice (rather than those which are merely theoretical) by sources of a similar type or character.'' A Legislative History of the Clean Air Act Amendments of 1990 (CAA Legislative History), Vol 5, pp. 8508–8509 (CAA Amendments of 1989; p. 168–169; Report of the Committee on Environment and Public Works S. 1630).

after May 3, 2011. An EGU is a fossil fuel-fired combustion unit of more than 25 megawatts (MW) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale is also considered an EGU. The 2012 MATS Final Rule defines additional terms for determining rule applicability, including, but not limited to, definitions for ''coal-fired electric utility steam generating unit,'' ''oil-fired electric utility steam generating unit,'' and ''fossil fuel-fired.'' In 2028, the EPA expects the source category covered by this MACT standard to include 314 coal-fired steam generating units (140 GW at 157 facilities), 58 oil-fired steam generating units (23 GW at 35 facilities), and 5 IGCC units (0.8 GW at 2 facilities).

For coal-fired EGUs, the 2012 MATS Final Rule established standards to limit emissions of Hg, acid gas HAP (*e.g.,* HCl, HF), non-Hg HAP metals (*e.g.,* nickel, lead, chromium), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Emission standards for HCl serve as a surrogate for the acid gas HAP, with an alternate standard for SO_2 that may be used as a surrogate for acid gas HAP for those coal-fired EGUs with flue gas desulfurization (FGD) systems and SO_2 CEMS installed and operational. Standards for fPM serve as a surrogate for the non-Hg HAP metals. Work practice standards limit formation and emissions of organic HAP.

For oil-fired EGUs, the 2012 MATS Final Rule established standards to limit emissions of HCl and HF, total HAP metals (*e.g.,* Hg, nickel, lead), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Standards for fPM also serve as a surrogate for total HAP metals, with standards for total and individual HAP metals provided as alternative equivalent standards. Work practice standards limit formation and emissions of organic HAP.

MATS includes standards for existing and new EGUs for eight subcategories: three for coal-fired EGUs, one for IGCC EGUs, one for solid oil-derived fuel-fired EGUs (*i.e.,* petroleum coke-fired), and three for liquid oil-fired EGUs. EGUs in seven of the subcategories are subject to numeric emission limits for all the pollutants described above except for organic HAP (limited-use liquid oil-fired EGUs are not subject to numeric emission limits). Emissions of organic HAP are regulated by a work practice standard that requires periodic combustion process tune-ups. EGUs in the subcategory of limited-use liquid oil-fired EGUs with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input are also subject to a work practice standard consisting of periodic combustion process tune-ups but are not subject to any numeric emission limits. Emission limits for existing EGUs and additional information of the history and other requirements of the 2012 MATS Final Rule are available in the 2023 Proposal preamble (88 FR 24854).

2. Public Health and Environmental Hazards Associated With Emissions From Coal- and Oil-Fired EGUs

Coal- and oil-fired EGUs are a significant source of numerous HAP that are associated with adverse effects to human health and the environment, including Hg, HF, HCl, selenium, arsenic, chromium, cobalt, nickel, hydrogen cyanide, beryllium, and cadmium emissions. Hg is a persistent and bioaccumulative toxic metal that, once released from power plants into the ambient air, can be readily transported and deposited to soil and aquatic environments where it is transformed by microbial action into methylmercury.[9] Methylmercury bioaccumulates in the aquatic food web eventually resulting in highly concentrated levels of methylmercury within the larger and longer-living fish (*e.g.,* carp, catfish, trout, and perch), which can then be consumed by humans.

Of particular concern is chronic prenatal exposure via maternal consumption of foods containing methylmercury. Elevated exposure has been associated with developmental neurotoxicity and manifests as poor performance on neurobehavioral tests, particularly on tests of attention, fine motor function, language, verbal memory, and visual-spatial ability. Evidence also suggests potential for adverse effects on the cardiovascular system, adult nervous system, and immune system, as well as potential for causing cancer. Because the impacts of the neurodevelopmental effects of methylmercury are greatest during periods of rapid brain development, developing fetuses, infants, and young children are particularly vulnerable. Children born to populations with high fish consumption (*e.g.,* people consuming fish as a dietary staple) or impaired nutritional status may be especially susceptible to adverse neurodevelopmental outcomes. These dietary and nutritional risk factors are often particularly pronounced in vulnerable communities with people of color and low-income populations that have historically faced economic and environmental injustice and are overburdened by cumulative levels of pollution. In addition to adverse neurodevelopmental effects, there is evidence that exposure to methylmercury in humans and animals can have adverse effects on both the developing and adult cardiovascular system.

Along with the human health hazards associated with methylmercury, it is well-established that birds and mammals are also exposed to methylmercury through fish consumption (Mercury Study). At higher levels of exposure, the harmful effects of methylmercury include slower growth and development, reduced reproduction, and premature mortality. The effects of methylmercury on wildlife are variable across species but have been observed in the environment for numerous avian species and mammals including polar bears, river otters, and panthers.

EGUs are also the largest source of HCl, HF, and selenium emissions, and are a major source of metallic HAP emissions including arsenic, chromium, nickel, cobalt, and others. Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* pneumonitis, decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys) and alimentary effects (such as nausea and vomiting). As of 2021, three of the key metal HAP emitted by EGUs (arsenic, chromium, and nickel) have been classified as human carcinogens, while three others (cadmium, selenium, and lead) are classified as probable human carcinogens. Overall (metal and nonmetal), the EPA has classified four of the HAP emitted by EGUs as human carcinogens and five as probable human carcinogens.

While exposure to HAP is associated with a variety of adverse effects, quantifying the economic value of these impacts remains challenging. Epidemiologic studies, which report a central estimate of population-level risk, are generally used in an air pollution benefits assessment to estimate the number of attributable cases of events. Exposure to HAP is typically more uneven and more highly concentrated among a smaller number of individuals than exposure to criteria pollutants.

[9] U.S. EPA. 1997, Mercury Study Report to Congress, EPA–452/R–97–003 (December 1997); *see also* 76 FR 24976 (May 3, 2011); 80 FR 75029 (December 1, 2015).

Hence, conducting an epidemiologic study for HAP is inherently more challenging; for starters, the small population size means such studies often lack sufficient statistical power to detect effects (particularly outcomes like cancer, for which there can exist a multi-year time lag between exposure and the onset of the disease). By contrast, sufficient power generally exists to detect effects for criteria pollutants because exposures are ubiquitous and a variety of methods exist to characterize this exposure over space and time.

For the reasons noted above, epidemiologic studies do not generally exist for HAP. Instead, the EPA tends to rely on experimental animal studies to identify the range of effects which may be associated with a particular HAP exposure. Human controlled clinical studies are often limited due to ethical barriers (*e.g.,* knowingly exposing someone to a carcinogen). Generally, robust data are needed to quantify the magnitude of expected adverse impacts from varying exposures to a HAP. These data are necessary to provide a foundation for quantitative benefits analyses but are often lacking for HAP, made even more challenging by the wide array of HAP and possible noncancer HAP effects.

Finally, estimating the economic value of HAP is made challenging by the human health endpoints affected. For example, though EPA can quantify the number and economic value of HAP-attributable deaths resulting from cancer, it is difficult to monetize the value of reducing an individual's potential cancer risk attributable to a lifetime of HAP exposure. An alternative approach of conducting willingness to pay studies specifically on risk reduction may be possible, but such studies have not yet been pursued.

C. Summary of the 2020 Residual Risk Review

As required by CAA section 112(f)(2), the EPA conducted the residual risk review (2020 Residual Risk Review) in 2020, 8 years after promulgating the 2012 MATS Final Rule, and presented the results of the review, along with our decisions regarding risk acceptability, ample margin of safety, and adverse environmental effects, in the 2020 Final Action. The results of the risk assessment are presented briefly in table 3 of this document, and in more detail in the document titled *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule* (risk document for the final rule), available in the docket (Document ID No. EPA–HQ–OAR–2018–0794–4553). The EPA summarized the results and findings of the 2020 Residual Risk Review in the preamble of the 2023 Proposal (88 FR 24854), and additional information concerning the residual risk review can be found in our *National-Scale Mercury Risk Estimates for Cardiovascular and Neurodevelopmental Outcomes for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Finding; Notice of Proposed Rulemaking* memorandum (Document ID No. EPA–HQ–OAR–2018–0794–4605).

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Table 3. Coal- and Oil-Fired EGU Inhalation Risk Assessment Results in the 2020 Final Action (85 FR 31286; May 22, 2020)

Number of Facilities[1]	Maximum Individual Cancer Risk (in 1 million)[2]		Population at Increased Risk of Cancer ≥ 1-in-1 million		Annual Cancer Incidence (cases per year)		Maximum Chronic Noncancer TOSHI[3]		Maximum Screening Acute Noncancer HQ[4]
322	Based on . . .		Based on . . .		Based on . . .		Based on . . .		Based on Actual Emissions Level
	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	
	9	10	193,000	636,000	0.04	0.1	0.2	0.4	HQ_{REL} = 0.09 (arsenic)

[1] Number of facilities evaluated in the risk analysis. At the time of the risk analysis there were an estimated 323 facilities in the Coal- and Oil-Fired EGU source category; however, one facility is located in Guam, which was beyond the geographic range of the model used to estimate risks. Therefore, the Guam facility was not modeled and the emissions for that facility were not included in the assessment.

[2] Maximum individual excess lifetime cancer risk due to HAP emissions from the source category.

[3] Maximum target organ-specific hazard index (TOSHI). The target organ systems with the highest TOSHI for the source category are respiratory and immunological.

[4] The maximum estimated acute exposure concentration was divided by available short-term threshold values to develop an array of hazard quotient (HQ) values. HQ values shown use the lowest available acute threshold value, which in most cases is the reference exposure level (REL). When an HQ exceeds 1, we also show the HQ using the next lowest available acute dose-response value.

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D. Summary of the 2020 Technology Review

Pursuant to CAA section 112(d)(6), the EPA conducted a technology review (2020 Technology Review) in the 2020 Final Action, which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since the 2012 MATS Final Rule was promulgated. Control technologies typically used to minimize emissions of pollutants that have numeric emission limits under the 2012 MATS Final Rule include electrostatic precipitators (ESPs) and fabric filters (FFs) for control of fPM as a surrogate for non-Hg HAP metals; wet scrubbers, dry scrubbers, and dry sorbent injection for control of acid gases (SO_2, HCl, and HF); and activated carbon injection (ACI) and other Hg-specific technologies for control of Hg. The EPA determined that the existing air pollution control technologies that were in use were well-established and provided the capture efficiencies necessary for compliance with the MATS emission limits. Based on the effectiveness and proven reliability of these control technologies, and the relatively short period of time since the promulgation of the 2012 MATS Final Rule, the EPA did not identify any developments in practices, processes, or control technologies, nor any new technologies or practices, for the control of non-Hg HAP metals, acid gas HAP, or Hg. However, in the 2020 Technology Review, the EPA did not consider developments in the cost and effectiveness of these proven technologies, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs, to determine whether revising the standards was warranted. Organic HAP, including emissions of dioxins and furans, are regulated by a work practice standard that requires periodic burner tune-ups to ensure good combustion. The EPA found that this work practice continued to be a practical approach to ensuring that combustion equipment was maintained and optimized to run to reduce emissions of organic HAP and continued to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. Based on the effectiveness and proven reliability of the work practice standard, and the relatively short amount of time since the promulgation of the 2012 MATS Final Rule, the EPA did not identify any developments in work practices nor any new work practices or operational procedures for this source category regarding the additional control of organic HAP.

After conducting the 2020 Technology Review, the EPA did not identify developments in practices, processes, or control technologies and, thus, did not propose changes to any emission standards or other requirements. More information concerning that technology review is in the memorandum titled Technology Review for the Coal- and Oil-Fired EGU Source Category, available in the docket (Document ID No. EPA–HQ–OAR–2018–0794–0015), and in the February 7, 2019, proposed rule. 84 FR 2700. On May 20, 2020, the EPA finalized the first technology review required by CAA section 112(d)(6) for the coal- and oil-fired EGU source category regulated under MATS. Based on the results of that technology review, the EPA found that no revisions to MATS were warranted. See 85 FR 31314 (May 22, 2020).

E. Summary of the EPA's Review of the 2020 RTR and the 2023 Proposed Revisions to the NESHAP

Pursuant to CAA section 112(d)(6), the EPA conducted a review of the 2020 Technology Review and presented the results of this review, along with our proposed decisions, in the 2023 Proposal. The results of the technology review are presented briefly below in this preamble. More detail on the proposed technology review is in the memorandum *2023 Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2023 Technical Memo'') (Document ID No. EPA–HQ–OAR–2018–0794–5789).

Based on the results of the technology review, the EPA proposed to lower the fPM standard, the surrogate for non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The Agency solicited comment on the control technology effectiveness and cost assumptions used in the proposed rule, as well as on a more stringent fPM limit of 0.006 lb/MMBtu or lower. Additionally, the Agency proposed to require the use of PM CEMS for all coal-fired, oil-fired, and IGCC EGUs for demonstrating compliance with the fPM standard. As the Agency proposed to require PM CEMS for compliance demonstration, we also proposed to remove the LEE option, a program based on infrequent stack testing, for fPM and non-Hg HAP metals. As EGUs would be required to demonstrate compliance with PM CEMS, the Agency also proposed to remove the alternate emission standards for non-Hg HAP metals and total HAP metals, because almost all regulated sources have chosen to demonstrate compliance with the non-Hg HAP metal standards by demonstrating compliance with the surrogate fPM standard, and solicited comment on prorated metal limits (adjusted proportionally according to the level of the final fPM standard), should the Agency not finalize the removal of the non-Hg HAP metals limits.

The Agency also proposed to lower the Hg emission standard for lignite-fired EGUs from 4.0 lb/TBtu to 1.2 lb/TBtu and solicited comment on the performance of Hg controls and on cost and effectiveness of control strategies to meet more stringent Hg standards. Lastly, the EPA did not identify new developments in control technologies or improved methods of operation that would warrant revisions to the Hg emission standards for non-lignite EGUs, for the organic HAP work practice standards, for the acid gas standards, or for standards for oil-fired EGUs. Therefore, the Agency did not propose changes to these standards in the 2023 Proposal but did solicit comment on the EPA's proposed findings that no revisions were warranted and on the appropriateness of the existing standards.

Additionally, the EPA proposed to remove one of the two options for defining the startup period for MATS-affected EGUs.

In the 2023 Proposal, the EPA determined not to reopen the 2020 Residual Risk Review, and accordingly did not propose any revisions to that review. As the EPA explained in the proposal, the EPA found in the 2020 RTR that risks from the Coal- and Oil-Fired EGU source category due to emissions of air toxics are acceptable and that the existing NESHAP provides an ample margin of safety to protect public health. As noted in the proposal, the EPA also acknowledges that it received a petition for reconsideration from environmental organizations that, in relevant part, sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review. The EPA granted in part the environmental organizations' petition which sought the EPA's review of startup and shutdown provisions in the 2023 Proposal, 88 FR 24885, and the EPA continues to review and will respond to other aspects of the petition in a separate action.[10]

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Coal- and Oil-Fired EGU source category and amends the Coal- and Oil-Fired EGU NESHAP based on those determinations. This action also finalizes changes to the definition of startup for this rule. This final rule includes changes to the 2023 Proposal after consideration of comments received during the public comment period described in sections IV., V., VI., and VII. of this preamble.

A. What are the final rule amendments based on the technology review for the Coal- and Oil-Fired EGU source category?

We determined that there are developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the MACT standards by revising the fPM limit for existing coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu and requiring the use of PM CEMS for coal and oil-fired EGUs to demonstrate compliance with the revised fPM standard, as proposed. We are also finalizing, as proposed, a Hg limit for lignite-fired EGUs of 1.2 lb/TBtu, which aligns with the existing Hg limit that has been in effect for other coal-fired EGUs since 2012. This revised Hg limit for lignite-fired EGUs is more stringent than the limit of 4.0 lb/TBtu that was finalized for such units in the 2012 MATS Final Rule. The rationale for these changes is discussed in more detail in sections IV. and V. below.

Based on comments received during the public comment period, the EPA is not finalizing the proposed removal of the non-Hg HAP metals limits for existing coal-fired EGUs (see section V.). Additionally, this final rule is requiring the use of PM CEMS for compliance demonstration for coal- and oil-fired EGUs (excluding EGUs in the limited-use liquid oil-fired subcategory), but not for IGCC EGUs (see section VI.).

Because this final rule includes revisions to the emissions standards for fPM as a surrogate for non-Hg HAP metals for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, the Hg emission standard for lignite-fired EGUs, and the definition of ''startup,'' the EPA intends each portion of this rule to be severable from each other as it is multifaceted and addresses several distinct aspects of MATS for independent reasons. This includes the revised emission standard for fPM as a surrogate for non-Hg HAP metals and the fPM compliance demonstration requirement to utilize PM CEMS. While the EPA considered the technical feasibility of PM CEMS in establishing the revised fPM standard, the EPA finds there are independent reasons for adopting each revision to the standards, and that each would continue to be workable without the other in the place.

[10] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov*.

The EPA intends that the various pieces of this package be considered independent of each other. For example, the EPA notes that our judgments regarding developments in fPM control technology for the revised fPM standard as a surrogate for non-Hg HAP metals largely reflect that the fleet was reporting fPM emission rates well below the current standard and with lower costs than estimated during promulgation of the 2012 MATS Final Rule; while our judgments regarding the ability for lignite-fired EGUs to meet the same standard for Hg emissions as other coal- and oil-fired EGUs rest on a separate analysis specific to lignite-fired units. Thus, the revised fPM surrogate emissions standard is feasible and appropriate even absent the revised Hg standard for lignite-fired units, and vice versa. Similarly, the EPA is finalizing changes to the fPM compliance demonstration requirement based on the technology's ability to provide increased transparency for owners and operators, regulators, and the public; and the EPA is finalizing changes to the startup definition based on considerations raised by environmental groups in petitions for reconsideration. Both of these actions are independent from the EPA's revisions to the fPM surrogate standard, and the Hg standard for lignite-fired units. Accordingly, the EPA finds that each set of standards is severable from each other set of standards.

Finally, the EPA finds that implementation of each set of standards, compliance demonstration requirements, and revisions to the startup definition are independent. That is, a source can abide by any one of these individual requirements without abiding by any others. Thus, the EPA's overall approach to this source category continues to be fully implementable even in the absence of any one or more of the elements included in this final rule.

Thus, the EPA has independently considered and adopted each portion of this final rule (including the revised fPM emission standard as a surrogate for non-Hg HAP metals, the fPM compliance demonstration requirement, the revised Hg emission standard for lignite-fired units, and the revised startup definition) and each is severable should there be judicial review. If a court were to invalidate any one of these elements of the final rule, the EPA intends the remainder of this action to remain effective. Importantly, the EPA designed the different elements of this final rule to function sensibly and independently. Further, the supporting bases for each element of the final rule reflect the Agency's judgment that the element is independently justified and appropriate, and that each element can function independently even if one or more other parts of the rule has been set aside.

B. What other changes have been made to the NESHAP?

The EPA is finalizing, as proposed, the removal of the work practice standards of paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042. Under the first option, startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Under the second option, startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. The final rule requires that all EGUs use the work practice standards in paragraph (1) of the definition of ''startup,'' which is already being used by the majority of EGUs.

C. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on July 8, 2024. The compliance date for affected coal-fired sources to comply with the revised fPM limit of 0.010 lb/MMBtu and for lignite-fired sources to meet the lower Hg limit of 1.2 lb/TBtu is 3 years after the effective date of the final rule. The Agency believes this timeline is as expeditious as practicable considering the potential need for some sources to upgrade or replace pollution controls. As discussed elsewhere in this preamble, we are adding a requirement that compliance with the fPM limit be demonstrated using PM CEMS. Based on comments received during the comment period and our understanding of suppliers of PM CEMS, the EPA is finalizing the requirement that affected sources use PM CEMS for compliance demonstration by 3 years after the effective date of the final rule. The compliance date for existing affected sources to comply with amendments pertaining to the startup definition is 180 days after the effective date of the final rule, as few EGUs are affected, and changes needed to comply with paragraph (1) of startup are achievable by all EGUs at little to no additional expenditures. All affected facilities remain subject to the current requirements of 40 CFR part 63, subpart UUUUU, until the applicable compliance date of the amended rule.

The EPA has considered the concerns raised by commenters that these compliance deadlines could affect electric reliability and concluded that given the flexibilities detailed further in this section, the requirements of the final rule for existing sources can be met without adversely impacting electric reliability. In particular, the EPA notes the flexibility of permitting authorities to allow, if warranted, a fourth year for compliance under CAA section 112(i)(3)(B). This flexibility, if needed, would address many of the concerns that commenters raised. Furthermore, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides additional flexibilities to bring sources into compliance while maintaining reliability.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision. In the 2012 MATS Final Rule, the EPA emphasized that most units should be able to comply with the requirements of the final rule within 3 years. However, the EPA also made it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in a range of situations described in the 2012 MATS Final Rule preamble.[11] The EPA's Office of Enforcement and Compliance Assurance (OECA) also issued the MATS Enforcement Response policy (Dec. 16, 2011)[12] which described the approach regarding the issue of CAA section 113(a) administrative orders with respect to the sources that must operate in noncompliance with the MATS rule for up to 1 year to address specific documented reliability concerns. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection with the Enforcement Response policy. The 2012 MATS Final Rule was ultimately implemented over the 2015—2016 timeframe without challenges to grid reliability.

[11] 77 FR 9406.

[12] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

IV. What is the rationale for our final decisions and amendments to the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance options from the 2020 Technology Review?

In this section, the EPA provides descriptions of what we proposed, what we are finalizing, our rationale for the final decisions and amendments, and a summary of key comments and responses related to the emission standard for fPM, non-Hg HAP metals, and the compliance demonstration options. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the comment summary and response document *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* available in the docket.

Based on its review, the EPA is finalizing a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu and is requiring that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. The revised fPM standard will ensure that the entire fleet of coal-fired EGUs achieves performance levels that are consistent with those of the vast majority of regulated units operating today—*i.e.,* that the small minority of units that currently emit significantly higher levels of HAP than their peers use proven technologies to reduce their HAP to the levels achieved by the rest of the fleet. Further, the EPA finds that a 0.010 lb/MMBtu fPM emission standard is the lowest level currently compatible with PM CEMS for demonstrating compliance, which the EPA finds provides significant benefits including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. In addition, the rule's current requirement to shift electronic reporting of PM CEMS data to the Emissions Collection and Monitoring Plan System (ECMPS) will enable regulatory authorities, nearby citizens, and others, including members of the public and media, to quickly and easily locate, review, and download fPM emissions using simple, user-directed inquiries. An enhanced, web-based version of ECMPS (ECMPS 2.0) is currently being prepared that will ease data editing, importing, and exporting and is expected to be available prior to the date by which EGUs are required to use PM CEMS.

A. What did we propose pursuant to CAA section 112(d)(6) for the Coal- and Oil-Fired EGU source category?

1. Proposed Changes to the Filterable PM Standard

The EPA proposed to lower the fPM limit, a surrogate for total non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The EPA further solicited comment on an emission standard of 0.006 lb/MMBtu or lower. The EPA did not propose any changes to the fPM emission standard for oil-fired EGUs or for IGCC units. The EPA also proposed to remove the total and individual non-Hg HAP metals emission limits. The EPA also solicited comment on adjusting the total and individual non-Hg HAP metals emission limits proportionally to the revised fPM limit rather than eliminating the limits altogether.

2. Proposed Changes to the Requirements for Compliance Demonstration

The EPA proposed to require that all coal- and oil-fired EGUs (IGCC units are discussed in section VI.) use PM CEMS to demonstrate compliance with the fPM emission limit. The EPA also proposed to remove the option of demonstrating compliance using infrequent stack testing and the LEE program (where stack testing occurs quarterly for 3 years, then every third year thereafter) for both PM and non-Hg HAP metals.

B. How did the technology review change for the Coal- and Oil-Fired EGU source category?

1. Filterable PM Emission Standard

Commenters provided both supportive and opposing arguments for issues regarding the fPM limit that were presented in the proposed review of the 2020 Technology Review. Comments received on the proposed fPM limit for coal-fired EGUs, along with additional analyses, did not change the Agency's conclusions that were presented in the 2023 Proposal, and, therefore, the Agency is finalizing the 0.010 lb/MMBtu fPM emission limit for existing coal-fired EGUs, as proposed.

Additionally, commenters urged the Agency to retain the option of complying with individual non-Hg HAP metal (*e.g.,* lead, arsenic, chromium, nickel, and cadmium) emission rates or with a total non-Hg HAP metal emission rate. After consideration of public comments, the Agency is finalizing updated limits for non-Hg HAP metals and total non-Hg HAP metals that have been reduced proportional to the reduction of the fPM emission limit from 0.030 lb/MMBtu to the new final fPM emission limit of 0.010 lb/MMBtu. EGU owners or operators who would choose to comply with the non-Hg HAP metals emission limits instead of the fPM limit must request and receive approval of a non-Hg HAP metal CMS as an alternative test method (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f).

2. Compliance Demonstration Options

Comments received on the compliance demonstration options for coal- and oil-fired EGUs also did not change the results of the technology review, therefore the Agency is finalizing the use of PM CEMS for compliance demonstration purposes and removing the fPM and non-Hg HAP metals LEE options for all coal-fired EGUs and for oil-fired EGUs (except those in the limited use liquid oil-fired EGU subcategory). The Agency received comments that some PM CEMS that are currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience some difficulties should re-correlation be necessary at a lower fPM standard. Based on these comments and on additional review of PM CEMS test reports, as mentioned in sections IV.C.2. and IV.D.2., the Agency has made minor technical revisions to shift the basis of correlation testing from sampling a minimum volume per run to collecting a minimum mass or minimum sample volume per run and has adjusted the quality assurance (QA) criterion otherwise associated with the new emission limit. These changes will enable PM CEMS to be properly certified for use in demonstrating compliance with the lower fPM standard with a high degree of accuracy and reliability.

C. What key comments did we receive on the filterable PM and compliance options, and what are our responses?

1. Comments on the Filterable PM Emission Standard

Comment: Some commenters supported the proposed fPM limit of 0.010 lb/MMBtu as reasonable and achievable, noting that this limit is slightly greater than the fPM emission limit required for new and reconstructed units. Additionally, commenters stated CAA section 112 was intended to improve the performance of lagging industrial sources and that a standard that falls far behind what the vast majority of sources have already achieved, as the current standard does, is inadequate. Other commenters opposed the proposed fPM limit of 0.010 lb/MMBtu as too stringent. For instance, some commenters stated that the EPA did not provide adequate support for the proposed limit. Other commenters stated that the fact that the vast majority of units are achieving emission rates below the current limit does not constitute ''developments in practices, processes, and control technologies.''

Response: The EPA disagrees that the Agency has not adequately supported the proposed fPM limit. As described in the proposal preamble, the Agency conducted a review of the 2020 Technology Review pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since promulgation of the 2012 MATS Final Rule. Based on that review, the EPA found that a majority of sources were not only reporting fPM emissions significantly below the current emission limit, but also that the fleet achieved lower fPM rates at lower costs than the EPA estimated when it promulgated the 2012 MATS Final Rule. The EPA explains these findings in more detail in section IV.D.1. of this preamble and elsewhere in the record. Further, the EPA finds that there are technological developments and improvements in PM control technology, which also controls non-Hg HAP metals, since the 2012 MATS Final Rule that informed the 2023 Proposal and this action, as discussed further in section IV.D.1. below. For example, industry has implemented ''best practices'' for monitoring ESP operation more carefully, and more durable materials have been adopted for FFs since the 2012 MATS Final Rule. The EPA also finds that these are cognizable developments for purposes of CAA section 112(d)(6). As other commenters noted, in *National Association for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015), the D.C. Circuit found that the EPA ''permissibly identified and took into account cognizable developments'' based on the EPA's interpretation of the term as ''not only wholly new methods, but also technological improvements.'' Similarly, here the EPA identified a clear trend in control efficiency, costs, and technological improvements, which the EPA is accounting for in this action. Further, as discussed elsewhere in this section and in section IV.D.1. of this preamble, the EPA finds case law and substantial administrative precedent support the EPA's decision to update the fPM limit based upon these developments.

Comment: Many commenters recommended that the EPA add a compliance margin in its achievability assumptions. These commenters conveyed that most EGUs typically operate well below the limit to allow for a compliance margin in the event of an equipment malfunction or failure, which they encouraged the EPA to consider when setting new limits. These commenters claimed that with a proposed fPM limit of 0.010 lb/MMBtu, an appropriate design margin of 20 percent necessitates that control technologies must be able to achieve a limit of 0.008 lb/MMBtu or lower in practice. They also expressed concerns that the EPA did not take design margin into consideration in the cost analysis. They stated that by not including the need for a design margin, which the EPA has acknowledged the need for in at least two of the Agency's publications (*NESHAP Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired EGUs,* Document ID No. EPA–HQ–OAR–2009–0234–20223 and *PM CEMS Capabilities Summary for Performance Specification 11, NSPS, and MACT Rules,* Document ID No. EPA–HQ–OAR–2018–0794–5828), the EPA underpredicted the number of units that would require retrofits. These commenters stated that the combination of a very low fPM limit and having to account for the measurement uncertainty and correlation methodology of PM CEMS would likely necessitate an ''operational target limit'' of 50 percent of the applicable limit. Some commenters referenced the National Rural Electric Cooperative Association (NRECA) technical evaluation for the 2023 Proposal titled *Technical Comments on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.*[13] They said that, even using the EPA's unrealistic ''baseline fPM rates'' and the lowest possible compliance margin of 20 percent, the NRECA technical evaluation estimated that 37 units—almost twice as many as the EPA's estimate—would be required to take substantial action to comply with the proposed limit.

Response: The EPA agrees that most facility operators normally target an emission level below the emission limit by incorporating a compliance margin or margin of error in case of equipment malfunctions or failures. As the commenters noted, the Agency has previously recognized that some operators target an emission level 20 to 50 percent below the limit. However, no commenters provided data to suggest that ESPs or FF are unable to achieve a lower fPM limit. Furthermore, the Agency does not prescribe specifically how an EGU controls its emissions or how the unit operates. The choice to target a lower-level emission rate for a compliance margin is the sole decision of owners and operators. For facilities with more than one EGU in the same subcategory, owners or operators may find emissions averaging (40 CFR 63.10009), coupled with or without a compliance margin, could help the facility attain and maintain emission limits as an effective, low-cost approach. Additionally, no commenters provided data to indicate that every owner or operator aims to comply with the fPM limit with the same compliance margin. Because some operators might aim for a larger compliance margin than others, it would be difficult to select a particular assumption about compliance margin for the cost analysis. Every operator plans for compliance differently and the EPA cannot know every operator's plans for a compliance margin. Even if the EPA were to assume a 20 percent compliance margin in its evaluation of PM controls, the results of the analysis would not change the EPA's decision to adopt a lower fPM limit. Specifically, a 20 percent compliance margin assumption to a fPM limit of 0.010 lb/MMBtu would increase the number of affected EGUs from 33 to 53 (14.1 to 23.9 GW affected capacity) and the annual compliance costs from $87.2M to $147.7M. The number of EGUs that demonstrated an ability to meet the lower fPM limit, but do not do so on average and therefore would require O&M, would increase from 17 to 27 (including the compliance margin). Similarly, the number of ESP upgrades (previously 11) and bag upgrades (previously 3) would also increase (to 20 and 4, respectively). There would be no change in the number of new FF installs. Therefore, cost-effectiveness values for fPM and individual and total non-Hg HAP metals would only increase slightly. Moreover, the 30-boiler operating day averaging period using PM CEMS for compliance

[13] *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.* Cichanowicz, *et al.* June 19, 2023. Attachment A to Document ID No. EPA–HQ–OAR–2018–0794–5994.

demonstration provides flexibility for owners and operators to account for equipment malfunctions, operational variability, and other issues. Lastly, as described in the 2023 Proposal, and updated here, the vast majority of coal-fired EGUs are reporting fPM emissions well below the revised fPM limit. For instance, the median fPM rate of the 296 coal-fired EGUs assessed in the 2024 Technical Memo is 0.004 lb/MMBtu,[14] or 60 percent below the revised fPM limit of 0.010 lb/MMBtu. The median fPM rate of a quarter of the best performing sources (N=74) is 0.002 lb/MMBtu, about 80 percent below the revised fPM limit of 0.010 lb/MMBtu. Therefore, for these reasons, the EPA disagrees with commenters that a compliance margin needs to be considered in the cost analysis.

The updated PM analysis, detailed in the memorandum *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2024 Technical Memo'') available in the docket, estimates that the number of EGUs that will need to improve their fPM emission rate to achieve a 0.010 lb/MMBtu limit has increased from the 20 EGUs assumed in the 2023 Proposal to 33 EGUs, which is more consistent with the NRECA technical evaluation estimate of 37 EGUs. This increase is a result of updated methodology that utilizes both the lowest achieved fPM rate (*i.e.,* the lowest quarter's 99th percentile) and the average fPM rate across all quarterly data when assessing PM upgrade and costs assumptions for the evaluated limits. The Agency disagrees with the commenters, however, that the 37 EGUs in the NRECA technical evaluation would require ''substantial action to comply with the proposed standard.'' In the Agency's revised analysis, only 13 EGUs would require capital investments to meet a fPM limit of 0.010 lb/MMBtu. Of these, only two EGUs at one facility (Colstrip) currently without the most effective PM controls are projected to require installation of a FF, the costliest PM control upgrade option, to meet 0.010 lb/MMBtu. The remaining nine EGUs projected by the EPA to require capital investments are estimated to require various levels of ESP upgrades. The EPA estimates that more than half (20 EGUs) would be able to comply without any capital investments and would instead require improvements to their existing FF or ESP as they have already demonstrated the ability to meet the limit, but do not do so on average.

Comment: Some commenters stated that cost effectiveness is an important consideration in technology reviews under CAA section 112(d)(6) and acknowledged that the EPA undertook cost-effectiveness analyses for the three fPM standards on which the Agency sought comment. However, the commenters stated, the NRECA technical evaluation found meaningful errors in the EPA's cost analysis, including unreasonably low capital cost estimates for ESP rebuilds and a failure to consider the variability of fPM due to changes in operation or facility design, by not utilizing a compliance margin. They asserted that these errors resulted in sizeable cost-effectiveness underestimates that eroded the EPA's overall determination that the proposed fPM limit is cost-effective. These commenters also asserted that the EPA's rationale was arbitrary on its face because it reversed, without explanation, the EPA's prior acknowledgements that a cost-effectiveness analysis should account for the cost effectiveness of controls at each affected facility and not simply on an aggregate nationwide basis. They stated that facility-specific costs should factor into the EPA's assessment of what is ''necessary'' pursuant to the provisions of CAA section 112(d)(6) and CAA section 112(f)(2).

Some commenters asserted that, even using the EPA's cost-effectiveness figures, the proposed 0.010 lb/MMBtu limit is not cost-effective. These commenters stated that the EPA's proposal to revise the fPM standard to 0.010 lb/MMBtu based on a cost-effectiveness estimate of up to $14.7 million per ton of total non-Hg HAP metals removed (equivalent to $44,900 per ton of fPM removed) is inconsistent with the EPA's prior actions because the cost-effectiveness estimate is substantially higher than estimates the Agency has previously found to be not cost-effective. They further said that, in the past, the EPA has decided against revising fPM standards based on cost-effectiveness estimates substantially lower than the cost-effectiveness estimates here. They said that the EPA should follow these precedents and acknowledge that $12.2 to $14.7 million per ton of non-Hg HAP metals reduced is not cost-effective. They argued that the Agency should not finalize the proposed standard of 0.010 lb/MMBtu for that reason. Further, these commenters argued that the alternative, more stringent limit of 0.006 lb/MMBtu is even less cost-effective at $25.6 million per ton of non-Hg HAP metals reduced, so it should not be considered either.

The commenters provided the following examples of previous rulemakings where EPA found controls to not be cost-effective:

- In the Petroleum Refinery Sector technology review,[15] the EPA declined to revise the fPM emission limit for existing fluid catalytic cracking units after finding that it would cost $10 million per ton of total non-Hg HAP metals reduced (in that case, equivalent to $23,000 per ton of fPM reduced), which was not cost-effective.
- In the Iron Ore Processing technology review,[16] the EPA declined to revise the non-Hg HAP metals limit after finding that installing wet scrubbers would cost $16 million per ton of non-Hg HAP metals reduced, which was not cost-effective.
- In the Integrated Iron and Steel Manufacturing Facilities technology review,[17] the EPA declined to revise the non-Hg HAP metals limit after finding that upgrading all fume/flame suppressants at blast furnaces to baghouses would cost $7 million per ton of non-Hg HAP metals reduced, which was not cost-effective. The Agency made a similar finding for a proposed limit that would have cost $14,000 per ton of volatile HAP reduced.
- In the Portland Cement Manufacturing beyond-the-floor analysis,[18] the EPA declined to impose a more stringent non-Hg HAP metals limit because it resulted in ''significantly higher cost effectiveness for PM than EPA has accepted in other NESHAP.'' The EPA noted in that rulemaking that it had previously ''reject[ed] $48,501 per ton of PM as not cost-effective for PM,'' and noted prior EPA statements in a subsequent rulemaking providing that $268,000 per ton of HAP removed was a higher cost-effectiveness estimate than the EPA had accepted in other NESHAP rulemakings.

In contrast, other commenters focused on the EPA's estimated cost-effective estimates for fPM (which is a surrogate for non-Hg HAP metals) and argued that

[14] For the revised fPM analysis, the EPA uses two methods to assess the performance of the fleet: average and the 99th percentile of the lowest quarter of data. Values reported here use the average fPM rate for each EGU.

[15] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[16] *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 85 FR 45476, 45483 (July 28, 2020).

[17] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[18] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10021 (February 12, 2013).

those estimates were substantially lower than estimates that the EPA has considered to be cost-effective in other technology reviews. Therefore, these commenters concluded that the EPA should strengthen the limit to at least 0.010 lb/MMBtu. These commenters also pointed to a 2023 report by Andover Technology Partners [19] that found that the cost to comply with an emission limit of 0.006 lb/MMBtu on a fleetwide basis was significantly less than the costs estimated by the EPA. Andover Technology Partners attributed this difference ''to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu.'' These commenters stated that meeting the lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, and they urged the EPA to adopt this limit. They stated that although cost effectiveness is less relevant in the CAA section 112 context than for other CAA provisions, the $103,000 per ton of fPM and $209,000 per ton of filterable fine $PM_{2.5}$ estimates that the EPA calculated for the 0.006 lb/MMBtu limit were reasonable and comparable to past practice in technology reviews under CAA section 112(d)(6). They noted that the EPA has previously found a control measure that resulted in an inflation-adjusted cost of $185,000 per ton of $PM_{2.5}$ reduced to be cost-effective for the ferroalloys production source category [20] and proposed a limit for secondary lead smelting sources that cost an inflation-adjusted $114,000 per ton of fPM reduced.[21] They argued that, using the Andover Technology Partners cost estimates, the 0.006 lb/MMBtu limit has even better cost-effectiveness estimates at about $72,000 per ton of fPM reduced and $146,000 per ton of filterable $PM_{2.5}$ reduced. These commenters noted that the EPA also calculated cost effectiveness based on allowable emissions (*i.e.,* assuming emission reductions achieved if all evaluated EGUs emit at the maximum allowable amount of fPM, or 0.030 lb/MMBtu) at $1,610,000 per ton, showing that a limit of 0.006 lb/MMBtu allows far less pollution at low cost to the power sector. They concluded that all these metrics and approaches to considering costs show that a fPM limit of 0.006 lb/MMBtu would require cost-effective reductions and can be achieved at a reasonable cost that would not jeopardize the power sector's function.

Additionally, some commenters cited *Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981), and said the case supports the EPA's discretion to weigh cost, energy, and environmental impacts, recognizing the Agency's authority to take these factors into account ''in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.'' These commenters said that the EPA has the authority to require costs that are reasonable for the industry even if they are not reasonable for every facility. These commenters acknowledged that the EPA has discretion to consider cost effectiveness under CAA section 112(d)(2), citing *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014), but argued that the dollar-per-ton cost-effectiveness metric is less relevant under CAA section 112 than under other CAA provisions because the Agency is not charged with equitably distributing the costs of emission reductions through a uniform compliance strategy, as the EPA has done in its transport rules. The commenters concluded that the Agency should require maximum reductions of HAP emissions from each regulated source category and has no authority to balance cost effectiveness across industries.

Response: In this action, the EPA is acting under its authority in CAA section 112(d)(6) to ''review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards'' promulgated under CAA section 112. As the EPA explained in the 2023 Proposal, this technology review is separate and distinct from other standard-setting provisions under CAA section 112, such as establishing MACT floors, conducting the beyond-the-floor analysis, and reviewing residual risk.

Regarding the comments that the EPA underestimated costs to an extent that undermines the EPA's overall cost-effectiveness assumptions, the EPA disagrees that the Agency underestimated the typical costs of ESP rebuilds. The commenters provided cost examples from only two facilities to support their assertions regarding the costs of ESP rebuilds. The costs provided for one of those facilities, Labadie, were not the costs associated with an ESP rebuild, but instead were the costs associated with the full replacement of an ESP. The commenter stated that, ''Ameren retrofitted the entire ESP trains on two units in 2014/2015. On each of these units two of the three original existing ESPs had to be abandoned and one of the existing ESPs was retrofitted with new power supplies and flue gas flow modifications. A new state-of-the-art ESP was added to each unit to supplement the retrofitted ESPs.'' An ESP replacement is different from an ESP rebuild, and therefore the costs of an ESP replacement do not inform the costs of an ESP rebuild. The ESP rebuild cost provided for the other facility, Petersburg, was less than the EPA's final assumption regarding the typical cost of an ESP rebuild on a capacity-weighted average basis. Neither of these examples provided by the commenter demonstrate that the EPA underestimated costs. For these reasons, the EPA disagrees with these commenters. Additionally, the EPA disagrees with these commenters that the Agency must add a compliance margin in its cost assumptions. As described above, the Agency does not prescribe specifically how an EGU must be controlled or how it must be operated, and the choice of overcompliance is at the sole discretion of the owners and operators.

Generally, the EPA agrees with commenters that cost effectiveness, *i.e.,* the costs per unit of emissions reduction, is a metric that the EPA consistently considers, often alongside other cost metrics, in CAA section 112 rulemakings where it can consider costs, *e.g.,* beyond-the-floor analyses and technology reviews, and agrees with commenters who recognize that the Agency has discretion in how it considers statutory factors under CAA section 112(d)(6), including costs. *See e.g., Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013) (allowing that the EPA may consider costs in conducting technology reviews under CAA section 112(d)(6)); *see also Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA acknowledges that the cost-effectiveness values for these standards are higher than cost-effectiveness values that the EPA concluded were not cost-effective and weighed against implementing more stringent standards for some prior rules. The EPA disagrees, however, that there is any particular threshold that renders

[19] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[20] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37381 (June 30, 2015).

[21] *National Emission Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 76 FR 29032 (May 19, 2011).

a rule cost-effective or not.[22] The EPA's prior findings about cost effectiveness in other rules were specific to those rulemakings and the industries at issue in those rules. As commenters have pointed out, in considering cost effectiveness, the EPA will often consider what estimates it has deemed cost-effective in prior rulemakings. However, the EPA routinely views cost effectiveness in light of other factors, such as other relevant costs metrics (*e.g.,* total costs, annual costs, and costs compared to revenues), impacts to the regulated industry, and industry-specific dynamics to determine whether there are ''developments in practices, processes, and control technologies'' that warrant updates to emissions standards pursuant to CAA section 112(d)(6). Some commenters, pointing to prior CAA section 112 rulemakings where the EPA chose not to adopt more stringent controls, mischaracterized cost effectiveness as the sole criterion in those decisions. These commenters omitted any discussion of other relevant factors from those rulemakings that, in addition to cost effectiveness, counseled the EPA against adopting more stringent standards. For example, in the 2014 Ferroalloys rulemaking that commenters cited to, the EPA rejected a potential control option due to questions about technical feasibility and significant economic impacts the option would create for the industry, including potential facility closures that would impact significant portions of industry production.[23] In contrast here, the controls at issue are technically feasible (they are used at facilities throughout the country) and will not have significant effects on the industry. Indeed, the EPA does not project that the final revisions to MATS will result in incremental changes in operational coal-fired capacity.

Similarly, in the other rulemakings these commenters pointed to, where the EPA found similar cost-effectiveness values to those that the EPA identified for the revised fPM standard here, there are distinct aspects of those rulemakings and industries that distinguish those prior actions from this rulemaking. In the 2015 Petroleum Refineries rulemaking, the EPA considered the cost effectiveness of developments at only two facilities to decide whether to deploy a standard across the much wider industry.[24] Here in contrast, the EPA is basing updates to fPM standards for coal-fired EGUs on developments across the majority of the industry and the performance of the fleet as a whole, which has demonstrated the achievability of a more stringent standard. Additionally, there are inherent differences between the power sector and other industries that similarly distinguish prior actions from this rulemaking. For example, because of the size of the power sector (314 coal-fired EGUs at 157 facilities), and because this source category is one of the largest stationary source emitters of Hg, arsenic, and HCl and is one of the largest regulated stationary source emitters of total HAP,[25] even considering that this rule affects only a fraction of the sector, the estimated HAP reductions in this final rule (8.3 tpy) are higher than those in the prior rulemakings cited by the commenters (as are the estimated PM reductions (2,537 tpy) used as a surrogate for non-Hg HAP metals). In contrast, in the 2020 Integrated Iron and Steel Manufacturing rulemaking, the source category covered included only 11 facilities, and the estimated reductions the EPA considered would have removed 3 tpy of HAP and 120 tpy of PM.[26] Likewise, in the 2013 Portland Cement rulemaking, the EPA determined not to pursue more stringent controls for the sector after finding the standard would only result in 138 tpy of nationwide PM reductions and that there was a high cost for such modest reductions.[27] Here, the EPA estimates significantly greater HAP emission reductions, and fPM emission reductions that are orders of magnitude greater than both prior rulemakings.[28]

There are also unique attributes of the power sector that the EPA finds support the finalization of revised standards for fPM and non-Hg HAP metals despite the relatively high cost-effectiveness values of this rulemaking as compared to other CAA section 112 rulemakings. As the EPA has demonstrated throughout this record, there are hundreds of EGUs regulated under MATS with well-performing control equipment that are already reporting emission rates below the revised standards, whereas only a handful of facilities with largely outdated or underperforming controls are emitting significantly more than their peers. That means that the communities located near these handful of facilities may experience exposure to higher levels of toxic metal emissions than communities located near similarly sized well-controlled plants. This is what the revised standards seek to remedy, and as discussed throughout this record, this goal is consistent with the EPA's authority under CAA section 112(d)(6) and the purpose of CAA section 112 more generally.

U.S. EGUs are a major source of HAP metals emissions including arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, manganese, and selenium. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). The emissions reductions projected under this final rule from the use of PM controls are expected to reduce exposure of individuals residing near these facilities to non-Hg HAP metals, including carcinogenic HAP.

EGUs projected to be impacted by the revised fPM standards represent a small fraction of the total number of the coal-fired EGUs (11 percent for the 0.010 lb/MMBtu fPM limit). In addition, many regulated facilities are electing to retire

[22] See *e.g., National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (''[I]t is important to note that there is no bright line for determining acceptable cost effectiveness for HAP metals. Each rulemaking is different and various factors must be considered.'').

[23] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 79 FR 60238, 60273 (October 6, 2014).

[24] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[25] 2020 National Emissions Inventory (NEI) Data; *https://www.epa.gov/air-emissions-inventories/2020-national-emissions-inventory-nei-data.*

[26] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[27] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10020–10021 (February 12, 2013).

[28] In addition, while commenters are correct that the EPA determined not to adopt more stringent controls under the iron ore processing technology review, the aspects of the rulemaking that the commenters cite to concerned whether additional controls were necessary to provide an ample margin of safety under a residual risk review. In that instance, the EPA determined not to implement more stringent standards under the risk review based on the installation of wet ESPs in addition to wet scrubbers, based on the EPA's determination that such improvements were not necessary to provide an ample margin of safety to protect public health. See *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 84 FR 45476, 45483 (July 28, 2020).

due to factors independent of the EPA's regulations, and the EPA typically has more information on plant retirements for this sector than other sectors regulated under CAA section 112. Both of these factors contribute to relatively higher cost-effectiveness estimates in this rulemaking as compared to other sectors where the EPA is not able to account for facility retirements and factor in shorter amortization periods for the price of controls.

While some commenters stated that meeting an even lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, the Agency declines to finalize this limit primarily due to the technological limitations of PM CEMS at this lower emission limit (as discussed in more detail in sections IV.C.2. and IV.D.2. below). Additionally, the EPA considered the higher costs associated with a more stringent standard as compared to the final standard presented in section IV.D.1.

Finally, as mentioned in the Response to Comments document, the EPA finds that use of PM CEMS, which provide continuous feedback with respect to fPM variability, in lieu of quarterly fPM emissions testing, will render moot the commenter's suggestion that margin of compliance has not been taken into account.

Comment: Some commenters argued that the low residual risks the EPA found in its review of the 2020 Residual Risk Review obviate the need for the EPA to revise the standards under the separate technology review, and that residual risk should be a relevant aspect of the EPA's technology review of coal- and oil-fired EGUs. These commenters argued that it is arbitrary and capricious for the EPA to impose high costs on facilities, which they claimed will only result in marginal emission reductions, when the EPA determined there is not an unreasonable risk to the environment or public health.

Other commenters agreed with the EPA's ''two-pronged'' interpretation that CAA section 112(d)(6) provides authorities to the EPA that are distinct from the EPA's risk-based authorities under CAA section 112(f)(2). These commenters said that if the criteria under CAA section 112(d)(6) are met, the EPA must update the standards to reflect new developments independent of the risk assessment process under CAA section 112(f)(2). They said the technology-based review conducted under CAA section 112(d)(6) need not account for any information learned during the residual risk review under CAA section 112(f)(2) unless that information pertains to statutory factors under CAA section 112(d)(6), such as costs. They concluded that CAA section 112(d)(6) requires the EPA to promulgate the maximum HAP reductions possible where achievable at reasonable cost and is separate from the EPA's residual risk analysis.

Response: The EPA has an independent statutory authority and obligation to conduct the technology review separate from the EPA's authority to conduct a residual risk review, and the Agency agrees with commenters that recognized that the EPA is not required to account for information obtained during a residual risk review in conducting a technology review. The EPA's finding that there is an ample margin of safety under the residual risk review in no way interferes with the EPA's obligation to require more stringent standards under the technology review where developments warrant such standards. The D.C. Circuit has recognized the CAA section 112(d)(6) technology review and 112(f)(2) residual review are ''distinct, parallel analyses'' that the EPA undertakes ''[s]eparately.'' *Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 5 (D.C. Cir. 2015). In other recent residual risk and technology reviews, the EPA determined additional controls were warranted under technology reviews pursuant to CAA section 112(d)(6) although the Agency determined additional standards were not necessary to maintain an ample margin of safety under CAA section 112(f)(2).[29] The EPA has also made clear that the Agency ''disagree[s] with the view that a determination under CAA section 112(f) of an ample margin of safety and no adverse environmental effects alone will, in all cases, cause us to determine that a revision is not necessary under CAA section 112(d)(6).''[30] While the EPA has considered risks as a factor in some previous technology reviews,[31] that does not compel the Agency to do so in this rulemaking. Indeed, in other instances, the EPA has adopted the same standards under both CAA sections 112(f)(2) and 112(d)(6) based on independent rationales where necessary to provide an ample margin of safety and because it is technically appropriate and necessary to do so, emphasizing the independent authority of the two statutory provisions.[32]

The language and structure of CAA section 112, along with its legislative history, further underscores the independent nature of these two provisions.[33] While the EPA is only required to undertake the risk review once (8 years after promulgation of the original MACT standards), it is required to undertake the technology review multiple times (at least every 8 years after promulgation of the original MACT standard). That Congress charged the EPA to ensure an ample margin of safety through the risk review, yet still required the technology review to be conducted on a periodic basis, demonstrates that Congress anticipated that the EPA would strengthen standards based on technological developments even after it had concluded there was an ample margin of safety. CAA section 112's overarching charge to the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions)'' further demonstrates that Congress sought to minimize the emission of hazardous air pollution wherever feasible independent of a finding of risk. Moreover, as discussed *supra,* in enacting the 1990 CAA Amendments, Congress purposefully replaced the previous risk-based approach to establishing standards for HAP with a technology-driven approach. This technology-driven

[29] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Refractory Products Manufacturing Residual Risk and Technology Review,* 86 FR 66045 (November 19, 2021); *National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680 (July 10, 2020); *National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) Residual Risk and Technology Review,* 85 FR 40740, 40745 (July 7, 2020); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production,* 85 FR 40386, 40389 (July 6, 2020); *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills,* 82 FR 47328 (October 11, 2017); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards; and Manufacture of Amino/Phenolic Resins,* 79 FR 60898, 60901 (October 8, 2014).

[30] *National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry,* 76 FR 22566, 22577 (April 21, 2011).

[31] See, *e.g., National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry,* 71 FR 76603, 76606 (December 21, 2006); *see also Proposed Rules: National Emission Standards for Halogenated Solvent Cleaning,* 73 FR 62384, 62404 (October 20, 2008).

[32] *National Emissions Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012).

[33] See section II.A.2. above for further discussion of the statutory structure and legislative history of CAA section 112.

approach recognizes the ability for the EPA to achieve substantial reductions in HAP based on technological improvements without the inherent difficulty in quantifying risk associated with HAP emission exposure given the complexities of the pathways through which HAP cause harm and insufficient availability of data to quantify their effects discussed in section II.B.2. Independent of risks, it would be inconsistent with the text, structure, and legislative history for the EPA to conclude that Congress intended the statute's technology-based approach to be sidelined after the EPA had concluded the risk review.

Comment: Some commenters expressed concern that some portion of affected units could simply retire instead of coming into compliance with new requirements, potentially occurring before new generation could be built to replace the lost generation. During this period, a lack of dispatchable generation could significantly increase the likelihood of outages, particularly during periods of severe weather. In addition, some commenters argued that revising the fPM limit was unnecessary as there is a continuing downward trend in HAP emissions from early retirements of coal-fired EGUs, whereas accelerating this trend could have potential adverse effects on reliability. Some commenters also stated that as more capacity and generation is shifted away from coal-fired EGUs due to the Inflation Reduction Act (IRA) and other regulatory and economic factors, the total annual fPM and HAP emissions from industry will decline, regardless of whether the fPM limit is made more stringent.

Response: The EPA disagrees that this rule would threaten resource adequacy or otherwise degrade electric system reliability. Commenters provided no credible information supporting the argument that this final rule would result in a significant number of retirements or a larger amount of capacity needing controls. The Agency estimates that this rule will require additional fPM control at less than 12 GW of operable capacity in 2028, which is about 11 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM controls are projected to generate less than 1.5 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule. Because the EPA projects no incremental changes in existing operational capacity to occur in response to the final rule, the EPA does not anticipate this rule will have any implications for resource adequacy.

Nevertheless, it is possible that some EGU owners may conclude that retiring a particular EGU and replacing it with new capacity is a more economic option from the perspective of the unit's customers and/or owners than making investments in new emissions controls at the unit. The EPA understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some commenters nevertheless assume without any rationale that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service.

In addition, the Agency has granted the maximum time allowed for compliance under CAA section 112(i)(3) of 3 years, and individual facilities may seek, if warranted, an additional 1-year extension of the compliance date from their permitting authority pursuant to CAA section 112(i)(3)(B). The construction of any additional pollution control technology that EGUs might install for compliance with this rule can be completed within this time and will not require significant outages beyond what is regularly scheduled for typical maintenance. Facilities may also obtain, if warranted, an emergency order from the Department of Energy pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) that would allow the facility to temporarily operate notwithstanding environmental limits when the Secretary of Energy determines doing so is necessary to address a shortage of electric energy or other electric reliability emergency.

Further, despite the comments asserting concerns over electric system reliability, no commenter cited a single instance where implementation of an EPA program caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior CAA rulemakings have not been borne out in reality. For example, in the stay litigation over the Cross-State Air Pollution Rule (CSAPR), claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets. Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emission reduction targets years ahead of schedule without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) (''[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own . . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' '') (quoting 84 FR 32561). In other words, the claims that these rules would have had adverse reliability impacts proved to be groundless.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision.[34] As with the current rule, the flexibility of permitting authorities to allow a fourth year for compliance was available in a broad range of situations, and in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability. We have seen no evidence in the last decade to suggest

[34] The EPA projected that the 2012 MATS Final Rule would drive the installation of an additional 20 GW of dry FGD (dry scrubbers), 44 GW of DSI, 99 GW of additional ACI, 102 GW of additional FFs, 63 GW of scrubber upgrades, and 34 GW of ESP upgrades. While a subsequent analysis found that the industry ultimately installed fewer controls than was projected, the control installations that occurred following the promulgation of the 2012 MATS Final Rule were still significantly greater than the installations that are estimated to occur as a result of this final rule (where, for example, the EPA estimates that less than 2 GW of capacity would install FF technology for compliance).

that the implementation of MATS caused power sector adequacy and reliability problems, and only a handful of sources obtained administrative orders under the enforcement policy issued with MATS to provide relief to reliability critical units that could not comply with the rule by 2016.

Comment: Commenters suggested that the EPA use its authority to create subcategories of affected facilities that elect to permanently retire by the compliance date as the Agency has taken in similar proposed rulemakings affecting coal- and oil-fired EGUs. Commenters stated the EPA should subcategorize those sources that have adopted enforceable retirement dates and not subject those sources to any final rule requirements. They indicated that the EPA is fully authorized to subcategorize these units under CAA section 112(d)(1). Commenters asked that the EPA consider other simultaneous rulemakings, such as the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel Power Plants,[35] where the EPA proposed that EGUs that elect to shut down by January 1, 2032, must maintain their recent historical carbon dioxide (CO_2) emission rate via routine maintenance and operating procedures (*i.e.,* no degradation of performance). Commenters also referenced the retirement date of December 31, 2032, in the EPA Office of Water's proposed Effluent Limitation Guidelines.[36]

Commenters claimed that creating a subcategory for units facing near-term retirements that harmonizes the retirement dates with other rulemakings would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, forced to deliberate whether to install controls and delaying retirement to recoup investments in the controls. Commenters also suggested that EGUs with limited continued operation be allowed to continue to perform quarterly stack testing to demonstrate compliance with the fPM limitations (rather than having to install PM CEMS). Commenters suggested that imposing different standards on these subcategories should continue the status quo for these units until retirement. Commenters claimed that it would make no sense for the EPA to require an EGU slated to retire in the near term to expend substantial resources on controls in the interim since these sources are very unlikely to find it viable to construct significant control upgrades for a revised standard that would become effective in mid-2027, only 5 years before the unit's permanent retirement. Commenters further noted if the EPA does not establish such a subcategory or take other action to ensure these units are not negatively impacted by the rulemaking, the retirement of some units could be accelerated due to the costs of installing a PM CEMS and the need to rebuild or upgrade an existing ESP or install a FF to supplement an existing ESP. Commenters stated that the EPA cannot ignore the need for a coordinated retirement of thermal generating capacity while new generation sources come online to avoid detrimental impacts to grid reliability.

Commenters suggested that if the EPA decides to proceed with finalizing the revised standards in the 2023 Proposal, the Agency should create a subcategory for coal-fired EGUs that elect by the compliance date of the revised standards (*i.e.,* mid-2027) to retire the units by December 31, 2032, or January 1, 2032, if the EPA prefers to tie the 2023 Proposal to the proposed Emission Guidelines instead of the Effluent Limitation Guidelines, and maintain the current MATS standards for this subcategory of units. Commenters requested that the EPA coordinate the required retirement date for the 2023 Proposal with other rules so that all retirement dates align. Commenters reiterated that the EPA has multiple authorities with overlapping statutory timelines that affect commenters' plans regarding the orderly retirement of coal-fired EGUs and their ability to continue the industry's clean energy transformation while providing the reliability and affordability that their customers demand. Commenters suggested that EGUs that plan to retire by 2032 should have the opportunity to seek a waiver from PM CEMS installation altogether and continue quarterly stack testing during the remaining life of the unit. They also suggested that if a unit does not retire by the specified date, it should be required to immediately cease operation or meet the standards of the rule. Commenters stated that under this recommendation an EGU's failure to comply would then be a violation of the 2023 Proposal's final rule subject to enforcement.

Response: In response to commenters' concerns, the EPA evaluated the feasibility of creating a subcategory for facilities with near-term retirements but disagrees with commenters that such a subcategory is appropriate for this rulemaking. In particular, the EPA found that, based on its own assessment and that of commenters, only a few facilities would likely be eligible for a near-term retirement subcategory and that it would not significantly reduce the costs of the revised standards. According to the EPA's assessment, 67 of the 296 EGUs assessed[37] have announced retirements between 2029 and 2032—less than one-quarter of the fleet—and all but three of those EGUs (at two facilities) have already demonstrated the ability to comply with the 0.010 lb/MMBtu fPM standard on average. Additionally, these three EGUs already use PM CEMS to demonstrate compliance, therefore the comment requesting a waiver of PM CEMS installations for EGUs with near-term retirements is not relevant. Because the EPA's analysis led the Agency to conclude that there would be little utility to a near-term retirement subcategory and it would not change the costs of the rule in a meaningful way, the EPA determined not to create a retirement subcategory for the fPM standard. In addition, the EPA notes that allowing units to operate without the best performing controls for an additional number of years would lead to higher levels of non-Hg HAP metals emissions and continued exposure to those emissions in the communities around these units during that timeframe. Regarding a fPM compliance requirement subcategory for EGUs with near-term retirements, the Agency estimates 26 of 67 EGUs are already using PM CEMS for compliance demonstration and finds that the costs to install PM CEMS for facilities with near-term retirements are reasonable. The Agency finds that the transparency provided by PM CEMS and the increased ability to quickly detect and correct potential control or operational problems using PM CEMS furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring for all EGUs.

2. Comments on the Proposed Changes to the Compliance Demonstration Options

Comment: The Agency received both supportive and opposing comments requiring the use of PM CEMS for compliance demonstration. Supportive commenters stated the EPA must require the use of PM CEMS to monitor their emissions of non-Hg HAP metals

[35] 88 FR 33245 (May 23, 2023).

[36] 88 FR 18824, 18837 (March 29, 2023).

[37] In this final rule, the EPA reviewed fPM compliance data for 296 coal-fired EGUs expected to be operational on January 1, 2029. This review is explained in detail in the 2024 Technical Memo.

as PM CEMS are now more widely deployed than when MATS was first promulgated, and experience with PM CEMS has enabled operators to more promptly detect and correct problems with pollution controls as compared to other monitoring and testing options allowed under MATS (*i.e.,* periodic stack testing and parametric monitoring for PM), thereby lowering HAP emissions. They said that the fact that PM CEMS have been used to demonstrate compliance in a majority of units in the eight best performing deciles [38] provides strong evidence that PM CEMS can be used effectively to measure low levels of PM emissions.

Opposing commenters urged the EPA to retain all current options for demonstrating compliance with non-Hg HAP metal standards, including quarterly PM and metals testing, LEE, and PM CPMS. These commenters said removing these compliance flexibility options goes beyond the scope of the RTR and does not address why the reasons these options were originally included in MATS are no longer valid. Commenters said they have previously raised concerns about PM CEMS that the EPA has avoided by stating that CEMS are not the only compliance method for PM. They stated that previously, the EPA has determined these compliance methods were both adequate and frequent enough to demonstrate compliance.

Response: The Agency disagrees with commenters who suggests that the rule should retain all previous options for demonstrating compliance with either the individual metals, total metals, or fPM limits. Congress intended for CAA section 112 to achieve significant reductions of HAP, and the EPA agrees with other commenters that the use of CEMS in general and PM CEMS in particular enables owners or operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Consistent with the discussion contained in the 2023 Proposal (88 FR 24872), the Agency finds the transparency and ability to quickly detect and correct potential control or operational problems furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring.

Comment: Some commenters objected to the EPA's proposal to require the use of PM CEMS for purposes of demonstrating compliance with the revised fPM standard, stating that the requirements of Performance Specification 11 of 40 CFR part 60, appendix B (PS–11) will become extremely hard to satisfy at the low emission limits proposed. For PS–11, relative correlation audit (RCA), and relative response audit (RRA), the tolerance interval and confidence interval requirements are expressed in terms of the emission standard that applies to the source. The commenters reviewed test data from operating units and found significantly higher PS–11 failure (>80 percent), RCA failure (>80 percent), and RRA failure (60 percent) rates at the more stringent proposed emission limits. They stated that the cost, complexity, and failure rate of equipment calibration remains one of the biggest challenges with the use of PM CEMS and therefore other compliance demonstration methods should be retained. Commenters also noted that repeated tests due to failure could result in higher total emissions from the units.

Response: The Agency is aware of concerns by some commenters that PM CEMS currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience difficulties should re-correlation be necessary; and those concerns are also ascribed to yet-to-be installed PM CEMS. In response to those concerns, the Agency has shifted the basis of correlation testing from requiring only the collection of a minimum volume per run to also allowing the collection of a minimum mass per run and has adjusted the QA criterion otherwise associated with the new emission limit. These changes will ease the transition for coal- and oil-fired EGUs using only PM CEMS for compliance demonstration purposes. The first change, allowing the facility to choose either the collection of a minimum mass per run or a minimum volume per run, should reduce high-level correlation testing duration, addressing other concerns about extended runtimes with degraded emissions control or increased emissions, and should reduce correlation testing costs. The second change, adjusting the QA criteria, is consistent with other approaches the Agency has used when lower ranges of instrumentation or methods are employed. For example, in section 13.2 of Performance Specification 2 (40 CFR part 60, appendix B) the QA criteria for the relative accuracy test audit for SO_2 and Nitrogen Oxide CEMS are relaxed as the emission limit decreases. This is accomplished at lower emissions by allowing a larger criterion or by modifying the calculation and allowing a less stringent number in the denominator. With these changes to the QA criteria and correlation procedures, the EPA believes EGUs will be able to use PM CEMS to demonstrate compliance at the revised level of the fPM standard.

Comment: Some commenters asserted that if the EPA finalizes the requirement to demonstrate compliance using PM CEMS, EGUs will not be able to comply with a lower fPM limit on a continuous basis and that accompanying a lower limit with more restrictive monitoring requirements adds to the regulatory burden of affected sources and permitting authorities.

Response: The EPA disagrees with commenters' claim that that EGUs will not be able to demonstrate compliance continuously with a fPM limit of 0.010 lb/MMBtu. The EPA believes that CEMS in general and PM CEMS in particular enable owners and operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Contrary to the commenter's assertion that EGUs will not be able to comply with a lower fPM limit on a continuous basis, as mentioned in the June 2023 Andover Technology Partners analysis,[39] over 80 percent of EGUs using PM CEMS for compliance purposes have already been able to achieve and are reporting and certifying consistent achievement of fPM rates below 0.010 lb/MMBtu.[40] The EPA is unaware of any additional burden experienced by those EGU owners or operators or their regulatory authorities with regard to PM CEMS use at these lower emission levels, and does not expect additional burden to be placed on EGU owners or operators with regard to PM CEMS from application of the revised emission limit. However, this final rule incorporates approaches, such as switching from a minimum sample volume per run to collection of a

[38] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[39] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. June 2023. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[40] See for example the PM CEMS Thirty Boiler Operating Day Rolling Average Reports for Duke's Roxboro Steam Electric Plant in North Carolina and at Minnesota Power's Boswell Energy Center in Minnesota. These reports and those from other EGUs reporting emission levels at or lower than 0.010 lb/MMBtu are available electronically by searching in the EPA's Web Factor Information Retrieval System (WebFIRE) Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

minimum mass sample or mass volume per run and adjusting the PM CEMS QA acceptability criteria, to reduce the challenges with using PM CEMS. Moreover, the 30-boiler-operating-day averaging period of the limit provides flexibility for owners and operators to account for equipment malfunctions and other issues. Consistent with the discussion in the 2023 Proposal,[41] the Agency finds that PM CEMS are the best choice for this rule's compliance monitoring as they provide increased emissions transparency, ability for EGU owner/operators to quickly detect and correct potential control or operational problems, and greater assurance of continuous compliance. While PM CEMS can produce values at lower levels provided correlations are developed appropriately, the Agency established the final fPM limit of 0.010 lb/MMBtu after considering factors such as run times necessary to develop correlations, potential random error effects, and costs.

Comment: Commenters stated that the EPA's cost estimates contradict the Agency's suggestion that the use of PM CEMS is a more cost-effective monitoring approach than quarterly testing, especially for units that qualify as LEE. They said that the EPA used estimates from the Institute of Clean Air Companies (ICAC) or Envea/Altech which do not include numerous costs associated with PM CEMS that make them not cost-effective, such as the cost of intermittent stack testing associated with the PS–11 correlations and the ongoing costs of RCAs and RRA, which are a large part of the costs associated with PM CEMS and would rise substantially in conjunction with the proposed new PM limits. The commenters said that the ICAC estimated range of PM CEMS installation costs are particularly understated and outdated and should be ignored by the Agency. They said that the EPA estimates may also understate PM CEMS cost by assuming the most commonly used light scattering based PM CEMS will be used for all applications. The commenters said that while more expensive, a significant number of beta gauge PM CEMS are used for MATS compliance, especially where PM spiking is used for PS–11 correlation and RCA testing and that this higher degree of accuracy from beta gauge PM CEMS may be needed for sources without a margin of compliance under the new, more stringent emission limit.

Response: The EPA disagrees with the commenters' suggestion that the Agency is required to select the most cost-effective approach for compliance monitoring. Rather, the Agency selects the approach that best provides assurance that emission limits are met. PM CEMS annual costs represent a very small fraction of a typical coal-fired EGU's operating costs and revenues. As described in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, available in the docket, if all coal-fired EGUs were to purchase and install new PM CEMS, the Equivalent Uniform Annual Cost (EUAC) would represent less than four hundredths of a percent of the average annual operating expenses from coal-fired EGUs.

Further, as described in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* technical memorandum, available in the rulemaking docket, the EPA calculated average costs for PM CEMS and quarterly testing from values submitted by commenters in response to the proposal's solicitation, which are discussed in section IV.D. of the preamble. Based on the commenters' suggestions, these revised costs include the costs of intermittent stack testing associated with the PS–11 correlations and ongoing costs of RCAs and RRAs. While the average EUAC for PM CEMS exceeds the average annual cost of quarterly stack emission testing, the cost for PM CEMS does not include important additional benefits associated with providing continuous emissions data to EGU owners or operators, regulators, nearby community members, or the general public. As a reminder, the EPA is not obligated to choose the most inexpensive approach for compliance demonstrations, particularly when all benefits are not monetized, even though costs can be an important consideration. Consistent with the discussion contained in the 2023 Proposal at 88 FR 24872, the Agency finds the increased transparency of EGU fPM emissions and the ability to quickly detect and correct potential control or operational problems, along with greater assurance of continuous compliance makes PM CEMS the best choice for this rule's compliance monitoring.

The Agency acknowledges the commenters' suggestions that EGU owners or operators may find that using beta gauge PM CEMS is most appropriate for the lower fPM emission limit in the rule; such suggestions are consistent with the Agency's view, as expressed in 88 FR 24872. However, the Agency believes other approaches, including spiking, can also ease correlation testing for PM CEMS. Moreover, the Agency anticipates that the new fPM limit will increase demand for, and perhaps spur increased production of, beta gauge PM CEMS.

D. What is the rationale for our final approach and decisions for the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance demonstration options?

The EPA is finalizing a lower fPM emission standard of 0.010 lb/MMBtu for coal-fired EGUs, as a surrogate for non-Hg HAP metals, and the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs (with the exception of limited-use liquid oil-fired EGUs) based on developments in the performance of sources within the category since the EPA finalized MATS and the advantages conferred by using CEMS for compliance. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in concomitant reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2). The EPA observes that since MATS was finalized, the vast majority of covered units have significantly outperformed the standard, with a small number of units lagging behind and emitting significantly higher levels of these HAP in communities surrounding those units. The EPA deems it appropriate to require these lagging units to bring their pollutant control performance up to that of their peers. Moreover, the EPA concludes that requiring use of PM CEMS for compliance yields manifold benefits, including increased emissions transparency and data availability for owners and operators and for nearby communities.

The EPA's conclusions with regard to the fPM standard and requirement to use PM CEMS for compliance demonstration are closely related, both in terms of CAA section 112(d)(6)'s direction for the EPA to reduce HAP emissions based on developments in practices, processes, and control technologies, and in terms of technical compatibility.[42] The EPA finds that the manifold benefits of PM CEMS render it appropriate to promulgate an updated fPM emission standard as a surrogate for non-Hg HAP metals for which PM CEMS can be used to monitor

[41] See 88 FR 24872.

[42] As noted in section III.A. above, there are nonetheless independent reasons for adopting both the revision to the fPM standard and the PM CEMS compliance demonstration requirement and each of these changes would continue to be workable without the other in effect, such that the EPA finds the two revisions are severable from each other.

compliance. However, as the fPM limit is lowered, operators may encounter difficulties establishing and maintaining existing correlations for the PM CEMS and may therefore be unable to provide accurate values necessary for compliance. The EPA has determined, based on comments and on the additional analysis described below, that the lowest possible fPM limit considering these challenges at this time is 0.010 lb/MMBtu with adjusted QA criteria. Therefore, the EPA determined that this two-pronged approach—requiring PM CEMS in addition to a lower fPM limit—is the most stringent option that balances the benefits of using PM CEMS with the emission reductions associated with the tightened fPM emission standard. Further, the EPA finds that the more stringent limit of 0.006 lb/MMBtu fPM cannot be adequately monitored with PM CEMS at this time, because the random error component of measurement uncertainty from correlation stack testing is too large and the QA criteria passing rate for PM CEMS is too small to provide accurate (and therefore enforceable) compliance values. Below, we further describe our rationale for each change.

1. Rationale for the Final Filterable PM Emission Standard

In the 2023 Proposal, the Agency proposed a lower fPM emission standard for coal-fired EGUs as a surrogate for non-Hg HAP metals based on developments in practices, processes, and control technologies pursuant to CAA section 112(d)(6), including the EPA's assessment of the differing performance of sources within the category and updated information about the cost of controls. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2).

In conducting this technology review, the EPA found important developments that informed its proposal. First, from reviewing historical information contained in WebFIRE,[43] the EPA observed that most EGUs were reporting fPM emission rates well below the 0.030 lb/MMBtu standard. The fleet was achieving these performance levels at lower costs than estimated during promulgation of the 2012 MATS Final Rule. Second, there are technical developments and improvements in PM control technology since the 2012 MATS Final Rule that informed the 2023 Proposal.[44] For example, while ESP technology has not undergone fundamental changes since 2011, industry has learned and adopted ''best practices'' associated with monitoring ESP operation more carefully since the 2012 MATS Final Rule. For FFs, more durable materials have been developed since the 2012 MATS Final Rule, which are less likely to fail due to chemical, thermal, or abrasion failure and create risks of high PM emissions. For instance, fiberglass (once the most widely used material) has largely been replaced by more reliable and easier to clean materials, which are more costly. Coated fabrics, such as Teflon or P84 felt, also clean easier than other fabrics, which can result in less frequent cleaning, reducing the wear that could damage filter bags and reduce the effectiveness of PM capture.

To examine potential revisions, the EPA evaluated fPM compliance data for the coal-fired fleet and evaluated the control efficiency and costs of PM controls to achieve a lower fPM standard. Based on comments received on the 2023 Proposal, the EPA reviewed additional fPM compliance data for 62 EGUs at 33 facilities (see 2024 Technical Memo and attachments for detailed information). The review of additional fPM compliance data showed that more EGUs had previously demonstrated an ability to meet a lower fPM rate, as shown in figure 4 of the 2024 Technical Memo. Compared to the 2023 Proposal where 91 percent of existing capacity demonstrated an ability to meet 0.010 lb/MMBtu, the updated analysis showed that 93 percent are demonstrating the ability to meet 0.010 lb/MMBtu with existing controls. The EPA received comments on the cost assumptions for upgrading PM controls and found that the costs estimated at proposal were not only too high, but that the cost effectiveness of PM upgrades was also underestimated (*i.e.,* the standard is more cost-effective than the EPA believed at proposal).

The EPA is finalizing the fPM emission limit of 0.010 lb/MMBtu with adjusted QA criteria, based on developments since 2012, for the reasons described in this final rule and in the 2023 Proposal as the lowest achievable fPM limit that allows for the use of PM CEMS for compliance demonstration purposes. First, this level of control ensures that the highest emitters bring their performance to a level where the vast majority of the fleet is already performing. For example, as described above, the majority of the existing coal-fired fleet subject to this final rule has previously demonstrated an ability to comply with the lower 0.010 lb/MMBtu fPM limit at least 99 percent of the time during one quarter, in addition to meeting the lower fPM limit on average across all quarters assessed. The Agency estimates that only 33 EGUs are currently operating above this revised limit. Compared to some of the best performing EGUs, the 33 EGUs requiring additional PM control upgrades or maintenance are more likely to have an ESP instead of a FF and to demonstrate compliance using intermittent stack testing. In addition, most of these EGUs have operated at a higher level of utilization than the coal-fired fleet on average.

Second, as discussed in section II.A.2. above, Congress updated CAA section 112 in the 1990 Clean Air Act Amendments to achieve significant reductions in HAP emissions, which it recognized are particularly harmful pollutants, and implemented a regime under which Congress directed the EPA to make swift and substantial reductions to HAP based upon the most stringent standards technology could achieve. This is evidenced by Congress's charge to the EPA to ''require the maximum degree of reduction in emissions of hazardous air pollutants (including a prohibition on such emissions),'' that is achievable accounting for ''the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements. . . .'' CAA section 112(d)(2). Further, by creating separate and distinct requirements for the EPA to consider updates to CAA section 112 pursuant to both technology review under CAA section 112(d)(6) and residual risk review under CAA section 112(f)(2), Congress anticipated that the EPA would strengthen standards pursuant to technology reviews ''as necessary (taking into account developments in practices, processes, and control technologies),'' CAA section 112(d)(6), even after the EPA concluded there was an ample margin of safety based on the risks that the EPA can quantify.[45] As the EPA explained in the

[43] WebFIRE includes data submitted to the EPA from the Electronic Reporting Tool (ERT) and is searchable at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[44] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[45] EPA's CAA section 112(f)(2) quantitative risk assessments evaluate cancer risk associated with a lifetime of exposure to HAP emissions from each source in the source category, the potential for HAP exposure to cause adverse chronic (or long-term) noncancer health effects, and the potential for HAP

proposal, the EPA does consider costs, technical feasibility, and other factors when evaluating whether it is necessary to revise existing emission standards under CAA section 112(d)(6) to ensure the standards ''require the maximum degree of emissions reductions . . . achievable.'' CAA section 112(d)(2). The text, structure, and history of this provision demonstrate Congress's direction to the EPA to require reduction in HAP where technology is available to do so and the EPA accounts for the other statutory factors.

Accordingly, the EPA finds that bringing this small number of units to the performance levels of the rest of the fleet serves Congress's mandate to the EPA in CAA section 112(d)(6) to continually consider developments ''that create opportunities to do even better.'' *See LEAN,* 955 F.3d at 1093. As such, the EPA has a number of times in the past updated its MACT standards to reflect developments where the majority of sources were already outperforming the original MACT standards.[46] Indeed, this final rule is consistent with the EPA's authority pursuant to CAA section 112(d)(6) to take developments in practices, processes, and control technologies into account to determine if more stringent standards are achievable than those initially set by the EPA in establishing MACT floors, based on developments that occurred in the interim. *See LEAN* v. *EPA,* 955 F.3d 1088, 1097–98 (D.C. Cir. 2020). The technological standard approach of CAA section 112 is based on the premise that, to the extent there are controls available to reduce HAP emissions, and those controls are of reasonable cost, sources should be required to use them.

The fleet has been able to ''over comply'' with the existing fPM standard due to the very high PM control effectiveness of well-performing ESPs and FFs, often exceeding 99.9 percent. But the performance of a minority of units lags well behind the vast majority of the fleet. As indicated by the two highest fPM rates,[47] EGUs without the most effective PM controls have not been able to demonstrate fPM rates comparable to the rest of the fleet. Specifically, the Colstrip facility, a 1,500 MW subbituminous-fired power plant located in Colstrip, Montana, operates the only two coal-fired EGUs in the country without the most modern PM controls (*i.e.,* ESP or FF). Instead, this facility utilizes venturi wet scrubbers as its primary PM control technology and has struggled to meet the original 0.030 lb/MMBtu fPM limit, even while employing emissions averaging across the operating EGUs at the facility. Colstrip is also the only facility where the EPA estimates the current controls would be unable to meet a lower fPM limit. Specifically, the 2018 second quarter compliance stack tests showed average fPM emission rates above the 0.030 lb/MMBtu fPM limit, in violation of its Air Permit. Talen Energy, one of the owners of the facility, agreed to pay $450,000 to settle these air quality violations.[48] As a result, the plant was offline for approximately 2.5 months while the plant's operator worked to correct the problem. Comments from Colstrip's majority owners discuss the efforts this facility has undergone to improve their wet PM scrubbers, which they state remove 99.7 percent of the fly ash particulate but agree with the EPA that additional controls would be needed to meet a 0.010 lb/MMBtu limit. However, as stated in *NorthWestern Energy's Annual PCCAM Filing and Application of Tariff Changes*,[49] ''Colstrip has a history of operating very close to the upper end limit: for 43 percent of the 651 days of compliance preceding the forced outage its [Weighted Average Emission Rate or] WAER was within 0.03 lb/dekatherm[50] of the limit [. . . to comply with the Air Permit and MATS, Colstrip's WAER must be equal to or less than 0.03 lb/dekatherm].''

The Northern Cheyenne Reservation is 20 miles from the Colstrip facility and the Tribe exercised its authority in 1977 to require additional air pollution controls on the new Colstrip units (Colstrip 3 and 4, the same EGUs still operating today), recognizing the area as a Class I airshed under the CAA. According to comments submitted by the Northern Cheyenne Tribe, their tribal members—both those living on the Reservation and those living in the nearby community of Colstrip—have been disproportionally impacted by exposure to HAP emissions from the Colstrip facility.[51]

The EPA believes a fPM emission limit of 0.010 lb/MMBtu appropriately takes into consideration the costs of controls. The EPA evaluated the costs to improve current PM control systems and the cost to install better performing PM controls (*i.e.,* a new FF) to achieve a more stringent emission limit. Costs of PM upgrades are much lower than the EPA estimated in 2012, and the Agency revised its costs assumptions as described in the 2024 Technical Memo, available in the docket. Table 4 of this document summarizes the updated cost effectiveness of the three fPM emission limits considered in the 2023 Proposal for the existing coal-fired fleet. For the purpose of estimating cost effectiveness, the analysis presented in this table, described in detail in the 2023 and 2024 Technical Memos, is based on the observed emission rates of all existing coal-fired EGUs except for those that have announced plans to retire by the end of 2028. The analysis presented in table 4 estimated the costs associated for each unit to upgrade their existing PM controls to meet a lower fPM standard. In the cases where existing PM controls would not achieve the necessary reductions, unit-specific FF install costs were estimated. Unlike the cost and benefit projections presented in the RIA, the estimates in this table do not account for any future changes in the composition of the operational coal-fired EGU fleet that are likely to occur by 2028 as a result of other factors affecting the power sector, such as the IRA, future regulatory actions, or changes in economic conditions. For example, of the more than 14 GW of coal-fired capacity that the EPA estimates would require control improvements to achieve the final fPM rate, less than 12 GW is projected to be

exposure to cause adverse acute (or short-term) noncancer health effects.

[46] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680, 41698 (July 10, 2020) (proposed 84 FR 46138, 46161; September 3, 2019)) (requiring compliance with more stringent equipment leak definitions under a technology review, which were widely adopted by industry); *National Emissions Standards for Mineral Wool Production and Fiberglass Manufacturing,* 80 FR 45280, 45307 (July 29, 2015) (adopting more stringent limits for glass-melting furnaces under a technology review where the EPA found that ''all glass-melting furnaces were achieving emission reductions that were well below the existing MACT standards regardless of the control technology in use''); *National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012) (adopting more stringent stack lead emission limit under a technology review ''based on emissions data collected from industry, which indicated that well-performing baghouses currently used by much of the industry are capable of achieving outlet lead concentrations significantly lower than the [current] limit.'').

[47] See figure 4 of the 2024 Technical Memo.

[48] See Document CLT–1T Testimony, CLT–11, and CL–12 in Docket 190882 at *https://www.utc.wa.gov/documents-and-proceedings/dockets.*

[49] See NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes, Docket No. 2019.09.058, Final Order 7708f paragraph 21 (November 18, 2020) (noting that ''Colstrip has a history of operating very close to the upper end limit''), available at *https://reddi.mt.gov/prweb.*

[50] For reference, a dekatherm is equivalent to one million Btus (MMBtu).

[51] See Document ID No. EPA–HQ–OAR–2018–5984 at *https://www.regulations.gov.*

operational in 2028 (see section 3 of the RIA for this final rule).

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Table 4. Summary of the Updated Cost Effectiveness Analysis for Three Potential fPM Limits[1]

	Potential fPM emission limit (lb/MMBtu)		
	0.015	0.010	0.006
Affected Units (Capacity, GW)	11 (4.7)	33 (14.1)	94 (41.3)
Annual Cost ($M, 2019 dollars)	38.8	87.2	398.8
fPM Reductions (tpy)	1,258	2,526	5,849
Total Non-Hg HAP Metals Reductions (tpy)	3.0	8.3	22.7
Total Non-Hg HAP Metals Cost Effectiveness ($k/ton)	13,050	10,500	17,500
Total Non-Hg HAP Metals Cost Effectiveness ($/lb)	6,500	5,280	8,790

[1] This analysis used reported fPM compliance data for 296 coal-fired EGUs to develop unit-specific average and lowest achieved fPM rate values to determine if the unit, with existing PM controls, could achieve a lower fPM limit. Using the compliance data, the EPA evaluated costs to upgrade existing PM controls, or if necessary, install new controls in order to meet a lower fPM limit.

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The EPA has updated its costs analyses for this final rule based on comments received and additional data review, which is described in more detail in the 2024 Technical Memo available in the docket. In response to commenters stating that the use of the lowest quarter's 99th percentile, or the lowest achievable fPM rate, is not indicative of overall EGU operation and emission performance, the EPA added a review of average fPM rates. In these updated analyses, both the lowest quarter's 99th percentile and the average fPM rate must be below the potential fPM limit for the EPA to assume no additional upgrades are needed to meet a revised limit. If an EGU has previously demonstrated an ability to meet a potential lower fPM limit, but the average fPM rate is greater than the potential limit, the analysis for the final rule has been updated to assume increased bag replacement frequency (for units with FFs) or operation and maintenance costing $100,000/year (2022$). This additional cost represents increased vigilance in maintaining ESP performance and includes technician labor to monitor performance of the ESP and to periodically make typical repairs (*e.g.,* replacement of failed insulators, damaged electrodes or other internals that may fail, repairing leaks in the ESP casing, ductwork, or expansion joints, and periodic testing of ESP flow balance and any needed adjustments).

Additionally, the Agency received comments that the PM upgrade costs estimated at proposal were too high on a dollar per ton basis and these costs have been updated and are provided in the 2024 Technical Memo. Specifically, commenters demonstrated that the observed percent reductions in fPM attributable to ESP upgrades were significantly greater than the percent reductions that the EPA had assumed for the proposed rule. Additionally, commenters demonstrated that ESP performance guarantees for coal-fired utility boilers were much lower than the EPA was aware of at proposal. These updates, as well as improving our methodology which increases the number of EGUs estimated to need PM upgrades, slightly lower the dollar per ton estimates from what was presented in the 2023 Proposal.

The EPA considers costs in various ways, depending on the rule and affected sector. For example, the EPA has considered, in previous CAA section 112 rulemakings, cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues (*e.g.,* cost to revenue ratios).[52] As much of the

[52] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Mercury Cell Chlor-Alkali Plants Residual Risk and Technology Review,* 87 FR 27002, 27008 (May 6, 2022) (considered annual costs and average capital costs per facility in technology review and beyond-the-floor analysis); *National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review,*

fleet is already reporting fPM emission rates below 0.010 lb/MMBtu, both the total costs and non-Hg HAP metal reductions of the revised limit are modest in context of total PM upgrade control costs and emissions of the coal fleet. The cost-effectiveness estimate for EGUs reporting average fPM rates above the final fPM emission limit of 0.010 lb/MMBtu is $10,500,000/ton of non-Hg HAP metals, slightly lower than the range presented in the 2023 Proposal.

Further, the EPA finds that costs for facilities to meet the revised fPM emission limit represent a small fraction of typical capital and total expenditures for the power sector. In the 2022 Proposal (reaffirming the appropriate and necessary finding), the EPA evaluated the compliance costs that were projected in the 2012 MATS Final Rule relative to the typical annual revenues, capital expenditures, and total (capital and production) expenditures.[53] 87 FR 7648–7659 (February 9, 2022); 80 FR 37381 (June 30, 2015). Using electricity sales data from the U.S. Energy Information Administration (EIA), the EPA updated the analysis presented in the 2022 Proposal. We find revenues from retail electricity sales increased from $333.5 billion in 2000 to a peak of $429.6 billion in 2008 (an increase of about 29 percent during this period) and slowly declined since to a post-2011 low of $388.6 billion in 2020 (a decrease of about 10 percent from its peak during this period) in 2019 dollars.[54] Revenues increased in 2022 to nearly the same amount as the 2008 peak ($427.8 billion). The annual control cost estimate for the final fPM standard based on the cost-effectiveness analysis in table 4 (see section 1c of the 2024 Technical Memo) of this document is a very small share of total power sector sales (about 0.03 percent of the lowest year over the 2000 to 2019 period). Making similar comparisons of the estimated capital and total compliance costs to historical trends in sector-level capital and production costs, respectively, would yield similarly small estimates. Therefore, as in previous CAA section 112 rulemakings, the EPA considered costs in many ways, including cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues to determine the appropriateness of the revised fPM standard under the CAA section 112(d)(6) technology review, and determined the costs are reasonable.

In this final rule, the EPA finds that costs of the final fPM standard are reasonable, and that the revised fPM standard appropriately balances the EPA's obligation under CAA section 112 to achieve the maximum degree of emission reductions considering statutory factors, including costs. Further, the EPA finds that its consideration of costs is consistent with D.C. Circuit precedent, which has found that CAA section 112(d)(2) expressly authorizes cost consideration in other aspects of the standard-setting process, such as CAA section 112(d)(6), *see Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013), and that CAA section 112 does not mandate a specific method of cost analysis in an analogous situation when considering the beyond-the-floor review. *See NACWA* v. *EPA,* 734 F.3d 1115, 1157 (D.C. Cir. 2013) (finding the statute did not ''mandate a specific method of cost analysis''); *see also NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014).

As discussed in section IV.C.1. in response to comments regarding the relatively higher dollar per ton cost effectiveness of the final fPM standard, the EPA finds that in the context of this industry and this rulemaking, the updated standards are an appropriate exercise of the EPA's standard setting authority pursuant to the CAA section 112(d)(6) technology review. As commenters rightly note, the EPA routinely considers the cost effectiveness of potential standards where it can consider costs under CAA section 112, *e.g.,* in conducting beyond-the-floor analyses and technology reviews, to determine the achievability of a potential control option. And the D.C. Circuit recognized that the EPA's interpretation of costs as ''allowing consideration of cost effectiveness was reasonable.'' *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014) (discussing the EPA's consideration of cost effectiveness pursuant to a CAA section 112(d)(2) beyond-the-floor analysis). However, cost effectiveness is not the sole factor that the EPA considers when determining the achievability of a potential standard in conducting a technology review, nor is cost effectiveness the only value that the EPA considers with respect to costs.[55] Some commenters pointed to other rulemakings (which are discussed in section IV.C.1. above) where the EPA determined not to pursue potential control options with relatively higher cost-effectiveness estimates as compared to prior CAA section 112 rulemakings. However, there were other factors that the EPA considered, in addition to cost effectiveness, that counseled against pursuing such updates. In this rulemaking, the EPA finds that several factors discussed throughout this record make promulgation of the new fPM standard appropriate under CAA section 112(d)(6). First, a wide majority of units have invested in the most-effective PM controls and are already demonstrating compliance with the new fPM standard and at lower costs than assumed during promulgation of the original MATS fPM emission limit. Of the 33 EGUs that the EPA estimated would require control improvements to meet a 0.010 lb/MMBtu fPM standard, only two are not using the most effective PM control technologies available. The EPA assumed that these two units would need to install FFs to achieve the 0.010 lb/MMBtu emission standard, and the cost of those FF retrofits accounts for 42 percent of the total annualized costs presented in table 4. Further, 11 EGUs that the EPA assumed would require different levels of ESP upgrades to meet the 0.010 lb/MMBtu emission standard (all of which have announced retirement dates between 2031 and 2042 resulting in shorter assumed amortization periods) account for about 57 percent of the total annualized costs. The remaining 1 percent of the total annualized costs are associated with 10 EGUs with existing FFs that the EPA

87 FR 1616, 1635 (proposed January 11, 2022) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in proposed beyond-the-floor analysis); *Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing,* 80 FR 50386, 50398 (August 19, 2015) (considered total annual costs and capital costs compliance costs and annualized costs for technology review and beyond the floor analysis); *National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in technology review); *National Emission Standards for Hazardous Air Pollutants: Off-Site Waste and Recovery Operations,* 80 FR 14248, 14254 (March 18, 2015) (considered total annual costs and capital costs, and average annual costs and capital costs and annualized costs per facility in technology review); *National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants,* 77 FR 58220, 58226 (September 19, 2012) (considered total annual costs and capital costs in technology review); *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,* 77 FR 49490, 49523 (August 16, 2012) (considered total capital costs and annualized costs and capital costs in technology review). *C.f. NRDC* v. *EPA,* 749 F.3d 1055, 1060 (D.C. Cir. 2014).

[53] See Cost TSD for 2022 Proposal at Document ID No. EPA–HQ–OAR–2018–0794–4620 at *https://www.regulations.gov.*

[54] 2019 dollars were used for consistency with the 2023 Proposal.

[55] See note 50, above, for examples of other costs metrics the EPA has considered in prior CAA section 112 rulemakings.

assumes will require bag upgrades or increased bag changeouts and 10 EGUs that are assumed to need additional operation and maintenance of existing ESPs, which is further explained in the 2024 Technical Memo. Since only a small handful of units emit significantly more than peer facilities, the Agency finds these upgrades appropriate. Additionally, the size and unique nature of the coal-fired power sector, and the emission reductions that will be achieved by the new standard, in addition to the costs, make promulgation of the new standard appropriate under CAA section 112(d)(6).

The power sector also operates differently than other industries regulated under CAA section 112.[56] For example, the power sector is publicly regulated, with long-term decision-making and reliability considerations made available to the public; it is a data-rich sector, which generally allows the EPA access to better information to inform its regulation; and the sector is in the midst of an energy generation transition leading to plant retirements that are independent of EPA regulation. Because of the relative size of the power sector, while cost effectiveness of the final standard is relatively high as compared to prior CAA section 112 rulemakings involving other industries, costs represent a much smaller fraction of industry revenue. In the likely case that the power sector's transition to lower-emitting generation is accelerated by the IRA, for example, the total costs and emission reductions achieved by each final fPM standard in table 4 of this document would also be an overestimate.

As demonstrated in the proposal, the power sector, as a whole, is achieving fPM emission rates that are well below the 0.030 lb/MMBtu standard from the 2012 Final MATS Rule, with the exception of a few outlier facilities. The EPA estimates that only one facility (out of the 151 evaluated coal-fired facilities), which does not have the most modern PM pollution controls and has been unable to demonstrate an ability to meet a lower fPM limit, will be required to install the most-costly upgrade to meet the revised standards, which significantly drives up the cost of this final rule. However, the higher costs for one facility to install demonstrated improvements to its control technology should not prevent the EPA from establishing achievable standards for the sector under the EPA's CAA section 112(d)(6) authority. Instead, the EPA finds that it is consistent with its CAA section 112(d)(6) authority to consider the performance of the industry at large. The average fPM emissions of the industry demonstrate the technical feasibility of higher emitting facilities to meet the new standard and shows there are proven technologies that if installed at these units will allow them to significantly lower fPM and non-Hg HAP metals emissions.

In this rulemaking, the EPA also determined not to finalize a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu or lower, which the EPA took comment on in the 2023 Proposal. The EPA declines to finalize an emission standard of 0.006 lb/MMBtu or lower primarily due to technical limitations in using PM CEMS for compliance demonstration purposes described in the next section. The EPA has determined that a fPM emission standard of 0.010 lb/MMBtu is the lowest that would also allow the use of PM CEMS for compliance demonstration. Additionally, the EPA also considered the overall higher costs associated with a more stringent standard as compared to the final standard, which the EPA considered under the technology review.

Additionally, compliance with a fPM emission limit of 0.006 lb/MMBtu could only be demonstrated using periodic stack testing that would require test run durations longer than 4 hours[57] and would not provide the source, the public, and regulatory authorities with continuous, transparent data for all periods of operation. Establishing a fPM limit of 0.006 lb/MMBtu while maintaining the current compliance demonstration flexibilities of quarterly ''snapshot'' stack testing would, theoretically, result in greater emission reductions; however, the measured emission rates are only representative of rates achieved at optimized conditions at full load. While coal-fired EGUs have historically provided baseload generation, they are being dispatched much more as load following generating sources due to the shift to more available and cheaper natural gas and renewable generation. As such, traditional generation assets—such as coal-fired EGUs—will likely continue to have more startup and shutdown periods, more periods of transient operation as load following units, and increased operation at minimum levels, all of which can produce higher PM emission rates. Maintaining the status quo with quarterly stack testing will likely mischaracterize emissions during these changing operating conditions. Thus, while a fPM emission limit of 0.006 lb/MMBtu paired with use of quarterly stack testing may appear to be more stringent than the 0.010 lb/MMBtu standard paired with use of PM CEMS that the EPA is finalizing in this rule, there is no way to confirm emission reductions during periods in between quarterly tests when emission rates may be higher. Therefore, the Agency is finalizing a fPM limit of 0.010 lb/MMBtu with the use of PM CEMS as the only means of compliance demonstration. The EPA has determined that this combination of fPM limit and compliance demonstration represents the most stringent available option taking into account the statutory considerations.

The EPA also determined not to finalize a fPM standard of 0.015 lb/MMBtu, which the EPA took comment on in the 2023 Proposal, because the EPA determined that a standard of 0.010 lb/MMBtu is appropriate for the reasons discussed above.

In this rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the fPM emission standard and requirements to utilize PM CEMS. As discussed in section II.D. above, the 2020 Technology Review did not consider developments in the cost and effectiveness of proven technologies to control fPM as a surrogate for non-Hg HAP metals emissions, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs. In this rulemaking, in which the EPA reviewed the findings of the 2020 Technology Review, the Agency determined there are important developments regarding the emissions performance of the coal-fired EGU fleet, and the costs of achieving that performance that are appropriate for the EPA to consider under its CAA section 112(d)(6) authority, and which are the basis for the revised emissions standards the EPA is promulgating through this final rule.

The 2012 MATS Final Rule contains emission limits for both individual and total non-Hg HAP metals (*e.g.,* lead, arsenic, chromium, nickel, and cadmium), as well as emission limits for fPM. Those non-Hg HAP metals

[56] This is a fact which Congress recognized in requiring the EPA to first determine whether regulation of coal-fired EGUs was ''appropriate and necessary'' under CAA section 112(n)(1)(A) before proceeding to regulate such facilities under CAA section 112's regulatory scheme.

[57] Run durations greater than 4 hours would ensure adequate sample collection and lower random error contributions to measurement uncertainty for a limit of 0.006 lb/MMBtu. The EPA aims to keep run durations as short as possible, generally at least one but no more than 4 hours in length, in order to minimize impacts to the facility (*e.g.,* overall testing campaign testing costs, employee focused attention and safety).

emission limits serve as alternative emission limits because fPM was found to be a surrogate for either individual or total non-Hg HAP metals emissions. While EGU owners or operators may choose to demonstrate compliance with either the individual or total non-Hg HAP metals emission limits, the EPA is aware of just one owner or operator who has provided non-Hg HAP metals data—both individual and total—along with fPM data, for compliance demonstration purposes. This is for a coal refuse-fired EGU with a generating capacity of 46.1 MW. Given that owners or operators of all the other EGUs that are subject to the requirements in MATS have chosen to demonstrate compliance with only the fPM emission limit, the EPA proposed to remove the total and individual non-Hg HAP metals emission limits from all existing MATS-affected EGUs and solicited comment on our proposal. In the alternative, the EPA took comment on whether to retain total and/or individual non-Hg HAP metals emission limits that have been lowered proportionally to the revised fPM limit (*i.e.,* revised lower by two-thirds to be consistent with the revision of the fPM standard from 0.030 lb/MMBtu to 0.010 lb/MMBtu).

Commenters urged the EPA to retain the non-Hg HAP metals limits, arguing it is incongruous for the EPA to eliminate the measure for the pollutants that are the subject of regulation under CAA section 112(d)(6), notwithstanding the fact that the fPM limit serves as a more easily measurable surrogate for these HAP metals. Additionally, some commenters stated that the inability to monitor HAP metals directly will significantly impair the EPA's ability to revise emission standards in the future.

After considering comments, the EPA determined to promulgate revised total and individual non-Hg HAP metals emission limits for coal-fired EGUs that are lowered proportionally to the revised fPM standard. Just as this rule requires owners or operators to demonstrate continuous compliance with fPM limits, owners or operators who choose to demonstrate compliance with these alternative limits will need to utilize approaches that can measure non-Hg HAP metals on a continuous basis—meaning that intermittent emissions testing using Reference Method 29 will not be a suitable approach. Owners or operators may petition the Administrator to utilize an alternative test method that relies on continuous monitoring (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f). The EPA disagrees with the suggestion that failure to monitor HAP metals directly could impair the ability to revise those standards in the future.

2. Rationale for the Final Compliance Demonstration Options

In the 2023 Proposal, the EPA proposed to require that coal- and oil-fired EGUs utilize PM CEMS to demonstrate compliance with the fPM standard used as a surrogate for non-Hg HAP metals. The EPA proposed the requirement for PM CEMS based on its assessment of costs of PM CEMS versus stack testing, and the many other benefits of using PM CEMS including increased transparency and accelerated identification of anomalous emissions. In particular, the EPA noted the ability for PM CEMS to provide continuous feedback on control device and plant operations and to provide EGU owners and operators, regulatory authorities, and members of nearby communities with continuous assurance of compliance with emissions limits as an important benefit. Further, the EPA explained in the 2023 Proposal that PM CEMS are currently in use by approximately one-third of the coal-fired fleet, and that PM CEMS can provide low-level measurements of fPM from existing EGUs.

After considering comments and conducting further analysis,[58] the EPA is finalizing the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs pursuant to its CAA section 112(d)(6) authority. As discussed in section IV.D.1. above, Congress intended for CAA section 112 to achieve significant reductions in HAP, which it recognized as particularly harmful pollutants. The EPA finds that the benefits of PM CEMS to provide real-time information to owners and operators (who can promptly address any problems with emissions control equipment), to regulators, to adjacent communities, and to the general public, further Congress's goal to ensure that emission reductions are consistently maintained. The EPA determined not to require PM CEMS for existing IGCC EGUs, described in section VI.D., due to technical issues calibrating CEMS on these types of EGUs due to the difficulty in preparing a correlation range because these EGUs are unable to de-tune their fPM controls and their existing emissions are less than one-tenth of the final emission limit. Further, the EPA finds additional authority to require the use of PM CEMS under CAA section 114(a)(1)(C), which allows that the EPA may require a facility that ''may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter'' to ''install, use, and maintain such monitoring equipment'' on a ''on a one-time, periodic or continuous basis.'' 114(a)(1)(C).

From the EPA's review of PM CEMS, the Agency determined that a fPM standard of 0.010 lb/MMBtu with adjusted QA criteria—used to verify consistent correlation of CEMS data initially and over time—is the lowest fPM emission limit possible at this time with use of PM CEMS.[59] PM CEMS correlated using these values will ensure accurate measurements—either above, at, or below this emission limit. As discussed in section IV.D.1. above, one of the reasons the EPA determined not to finalize a more stringent standard for fPM is because it would prove challenging to verify accurate measurement of fPM using PM CEMS. Specifically, as mentioned in the *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels,* memorandum, available in the docket, no fPM standard more stringent than 0.010 lb/MMBtu with adjusted QA criteria is expected to have acceptable passing rates for the QA checks or acceptable random error for reference method testing.

At proposal, the EPA estimated that the EUAC of PM CEMS was $60,100 (88 FR 24873). Based on comments the EPA received on the costs and capabilities of PM CEMS and additional analysis the EPA conducted, the EPA determined that the revised EUAC of PM CEMS is higher than estimated at proposal. The EPA now estimates that the EUAC of non-beta gauge PM CEMS is $72,325, which is 17 percent less than what was estimated for the 2012 MATS Final Rule. That amount is somewhat greater than the revised estimated costs of infrequent emission testing (generally quarterly)—the revised average estimated costs of such infrequent emissions testing using EPA Method 5I[60] is $60,270.[61]

In choosing a compliance demonstration requirement, the EPA considers multiple factors, including

[58] The EPA explains additional analyses of PM CEMS in the memos titled *Suitability of PM CEMS Use for Compliance Determination for Various Emissions Levels* and *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, appendices B and F, respectively,* which are available in the docket.

[59] The EPA notes that the fPM standard [0.010 lb/MMBtu] is based on hourly averages obtained from PM CEMS over 30 boiler operating days [see 40 CFR 63.10021(b)].

[60] Method 5I is one of the EPA's reference test methods for PM. See 40 CFR part 60, appendix A.

[61] See *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* memorandum, available in the docket.

costs, benefits of the compliance technique, technical feasibility and commercial availability of the compliance method, ability of personnel to conduct the compliance method, and continuity of data used to assure compliance. PM CEMS are readily available and in widespread use by the electric utility industry, as evidenced by the fact that over 100 EGUs already utilize PM CEMS for compliance demonstration purposes. Moreover, the electric utility industry and its personnel have demonstrated the ability to install, operate, and maintain numerous types of CEMS—including PM CEMS. As mentioned earlier, EGU owners and/or operators who chose PM CEMS for compliance demonstration have attested in their submitted reports to the suitability of their PM CEMS to measure at low emission levels, certifying fPM emissions lower than 0.010 lb/MMBtu with their existing correlations developed using emission levels at 0.030 lb/MMBtu. The EPA conducted a review of eight EGUs with varying fPM control devices that rely on PM CEMS that showed certified emissions ranging from approximately 0.002 lb/MMBtu to approximately 0.007 lb/MMBtu. The EPA's review analyzed 30 boiler operating day rolling averages obtained from reports posted to WebFIRE for the third quarter of 2023 from these eight EGUs.[62]

As described in the *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, Appendices B and F* memorandum, available in the docket, the EPA investigated how well a sample of EGUs using PM CEMS for compliance purposes would meet initial and ongoing QA requirements at various emission limit levels, even though no change in actual EGU operation occurred. As described in the aforementioned *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels* memorandum, as the emission limit is lowered, the ability to meet both components necessary to correlate PM CEMS—acceptable random error and QA passing rate percentages—becomes more difficult. Based on this additional analysis and review, the EPA determined to finalize requirements to use PM CEMS with adjusted QA criteria and a 0.010 lb/MMBtu fPM emission limit as the most stringent limit possible with PM CEMS.

Use of PM CEMS can provide EGU owners or operators with an increased ability to detect and correct potential problems before degradation of emission control equipment, reduction or cessation of electricity production, or exceedances of regulatory emission standards. As mentioned in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, using PM CEMS can be advantageous, particularly since their EUAC is offset if their use allows owners or operators to avoid 3 or more hours of generating downtime per year.

In deciding whether to finalize the proposal to use PM CEMS as the only compliance demonstration method for non-IGCC coal- and oil-fired EGUs, the Agency assessed the costs and benefits afforded by requiring use of only PM CEMS as compared to continuing the current compliance demonstration flexibilities (*i.e.,* allowing use of either PM CEMS or infrequent PM emissions stack testing). As mentioned above, the average annual cost for quarterly stack testing provided by commenters is about $12,000 less than the EUAC for PM CEMS. While no estimate of quantified benefits was provided by commenters, the EPA recognizes that the 35,040 15-minute values provided by a PM CEMS used at an EGU operating during a 1-year period is over 243 times as much information as is provided by quarterly testing with three 3-hour run durations. This additional, timely information provided by PM CEMS affords the adjacent communities, the general public, and regulatory authorities with assurances that emission limits and operational processes remain in compliance with the rule requirements. It also provides EGU owners or operators with the ability to quickly detect, identify, and correct potential control device or operational problems before those problems become compliance issues. When establishing emission standards under CAA section 112, the EPA must select an approach to compliance demonstration that best assures compliance is being achieved.

The continuous monitoring of fPM required in this rule provides several benefits which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today. Continuous measurement of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that continuous monitoring could lead to lower fPM emissions for periods of time between otherwise required intermittent testing, currently up to 3 years for some units.

To illustrate the potentially substantial differences in fPM emissions between intermittent and continuous monitoring, the EPA analyzed emissions at several EGUs for which both intermittent and continuous monitoring data are available. This analysis is provided in the 2024 Technical Memo, available in the rulemaking docket. For example, one 585-MW bituminous-fired EGU, with a cold-side ESP for PM control, has achieved LEE status for fPM and is currently required to demonstrate compliance with an emission standard of 0.015 lb/MMBtu using intermittent stack testing every 3 years. In the most recent LEE compliance report, submitted on February 25, 2021, the unit submitted the result of an intermittent stack test with an emission rate of 0.0017 lb/MMBtu. In the subsequent 36 months over which this unit is currently not subject to any further compliance testing, continuous monitoring demonstrates that the fPM emission rate increased substantially. At one point, the continuously monitored 30-day rolling average emissions rate[63] was nine times higher than the intermittent stack test average, reaching the fPM LEE limit of 0.015 lb/MMBtu. In this example, the actual continuously monitored daily average emissions rate over the February 2021 to April 2023 period ranged from near-zero to 0.100 lb/MMBtu. Emissions using either the stack test average or hourly PM CEMS data were calculated for 2022 for this unit. Both approaches indicate fPM emissions well below the allowable levels for a fPM limit of 0.010 lb/MMBtu, while estimates using PM CEMS are about 2.5 times higher than the stack test estimate. Additional examples of differences between intermittent stack testing and continuous monitoring are provided in the 2024 Technical Memo, including for periods when PM CEMS data is lower

[62] See Third Quarter 2023 p.m. CEMS Thirty Boiler Operating Day Rolling Average Reports for Iatan Generating Station units 1 and 2, Missouri; Marshall Steam Station units 1 and 3, North Carolina; Kyger Creek Station unit 3, Ohio; Virginia City Hybrid Energy Center units 1 and 2, Virginia; and Ghent Generating Station unit 1, Kentucky. These reports are available electronically by searching in the WebFIRE Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[63] The 30-day rolling average emission rate was calculated by taking daily fPM rate averages over a 30-day operating period while filtering out hourly fPM data during periods of startup and shutdown.

than the stack test averages,[64] which further illustrate real-life scenarios in which fPM emissions for compliance methods may be substantially different.

The potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the total capacity that the EPA estimates would install PM CEMS under this rule (nearly 82 GW). Furthermore, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living in proximity to the coal-fired EGUs potentially impacted by the amended fPM standards. The EPA has found that populations living near coal-fired EGUs have a higher percentage of people living below two times the poverty level than the national average.

In addition to significant value of further pollution abatement, the CEMS data are transparent and accessible to regulators, stakeholders, and the public, fostering greater accountability. Transparency of EGU emissions as provided by PM CEMS, along with real-time assurance of compliance, has intrinsic value to the public and communities as well as instrumental value in holding sources accountable. This transparency is facilitated by a requirement for electronic reporting of fPM emissions data by the source to the EPA. This emissions data, once submitted, becomes accessible and downloadable—along with other operational and emissions data (*e.g.,* for SO_2, CO_2, NO_X, Hg, *etc.*) for each covered source.

On balance, the Agency finds that the benefits of emissions transparency and the continuous information stream provided by PM CEMS coupled with the ability to quickly detect and correct problems outweigh the minor annual cost differential from quarterly stack testing. The EPA is finalizing, as proposed, the use of PM CEMS to demonstrate compliance with the fPM emission standards for coal- and oil-fired EGUs (excluding IGCC units and limited-use liquid-oil-fired EGUs).

More information on the proposed technology review can be found in the 2023 Technical Memo (Document ID No. EPA–HQ–OAR–2018–0794–5789), in the preamble for the 2023 Proposal (88 FR 24854), and the 2024 Technical Memo, available in the docket. For the reasons discussed above, pursuant to CAA section 112(d)(6), the EPA is finalizing, as proposed, the use of PM CEMS (with adjusted QA criteria as a result of review of comments) for the compliance demonstration of the fPM emission standard (as a surrogate for non-Hg HAP metal) for coal- and oil-fired EGUs, and the removal of the fPM and non-Hg HAP metals LEE provisions.

V. What is the rationale for our final decisions and amendments to the Hg emission standard for lignite-fired EGUs from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the lignite-fired EGU subcategory?

In the 2012 MATS Final Rule, the EPA finalized a Hg emission standard of 4.0E-06 lb/MMBtu (4.0 lb/TBtu) for a subcategory of existing lignite-fired EGUs.[65] The EPA also finalized a Hg emission standard of 1.2E-06 lb/MMBtu (1.2 lb/TBtu) for coal-fired EGUs not firing lignite (*i.e.,* for EGUs firing anthracite, bituminous coal, subbituminous coal, or coal refuse); and the EPA finalized a Hg emission output-based standard for new lignite-fired EGUs of 0.040 lb/GWh and a Hg emission output-based standard for new non-lignite-fired EGUs of 2.0E-04 lb/GWh. In 2013, the EPA reconsidered the Hg emission standard for new non-lignite-fired EGUs and revised the output-based standard to 0.003 lb/GWh (see 78 FR 24075).

As explained in the 2023 Proposal, Hg emissions from the power sector have declined since promulgation of the 2012 MATS Final Rule with the installation of Hg-specific and other control technologies and as more coal-fired EGUs have retired or reduced utilization. The EPA estimated that 2021 Hg emissions from coal-fired EGUs were 3 tons (a 90 percent decrease compared to pre-MATS levels). However, units burning lignite (or permitted to burn lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in table 5 in the 2023 Proposal (88 FR 24876), 16 of the top 20 Hg-emitting EGUs in 2021 were lignite-fired EGUs. Overall, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs in 2021, while generating about 7 percent of total 2021 megawatt-hours. Lignite accounted for 8 percent of total U.S. coal production in 2021.

Prior to the 2023 Proposal, the EPA assembled information on developments in Hg emission rates and installed controls at lignite-fired EGUs from operational and emissions information that is provided routinely to the EPA for demonstration of compliance with MATS and from information provided to the EIA. In addition, the EPA's final decisions were informed by information that was submitted as part of a CAA section 114 information survey (2022 ICR). The EPA also revisited information that was used in establishing the emission standards in the 2012 Final MATS Rule and considered information that was submitted during the public comment period for the 2023 Proposal. From that information, the EPA determined, as explained in the 2023 Proposal, that there are available cost-effective control technologies and improved methods of operation that would allow existing lignite-fired EGUs to achieve a more stringent Hg emission standard. As such, the EPA proposed a revised Hg emission standard for existing EGUs firing lignite (*i.e.,* for those in the ''units designed for low rank virgin coal'' subcategory). Specifically, the EPA proposed that such lignite-fired units must meet the same emission standard as existing EGUs firing other types of coal (*e.g.,* anthracite, bituminous coal, subbituminous coal, and coal refuse), which is 1.2 lb/TBtu (or an alternative output-based standard of 0.013 lb/GWh). The EPA did not propose to revise the Hg emission standards either for existing EGUs firing non-lignite coal or for new non-lignite coal-fired EGUs.[66]

B. How did the technology review change for the lignite-fired EGU subcategory?

The outcome of the technology review for the Hg standard for existing lignite-fired EGUs has not changed since the 2023 Proposal. However, in response to comments, the EPA expanded its review to consider additional coal compositional data and the impact of sulfur trioxide (SO_3) in the flue gas.

[64] See Case Study 2 in the 2024 Technical Memo, which shows long time periods of PM CEMS data below the most recent RRA. Note this unit uses PM CEMS for compliance with the fPM standard, so the RRA is used as an indicator of stack test results.

[65] The EPA referred to this subcategory in the final rule as ''units designed for low rank virgin coal.'' The EPA went on to specify that such a unit is designed to burn and is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal. The EPA also finalized an alternative output-based emission standard of 0.040 lb/GWh. Currently, the approximately 22 units that are permitted as lignite-fired EGUs are located exclusively in North Dakota, Texas, and Mississippi.

[66] As stated in the 2023 Proposal, when proposed revisions to existing source emission standards are more stringent than the corresponding new source emission standard, the EPA proposes to revise the corresponding new source standard to be at least as stringent as the proposed revision to the existing source standard. This is the case with the Hg emission standard for new lignite-fired sources, which will be adjusted to be as stringent as the existing source standard.

C. What key comments did we receive on the Hg emission standard for lignite-fired EGUs, and what are our responses?

The Agency received both supportive and critical comments on the proposed revision to the Hg emission standard for existing lignite-fired EGUs. Some commenters agreed with the EPA's decision to not propose revisions to the Hg emission standards for non-lignite-fired EGUs, while others disagreed. Significant comments are summarized below, and the Agency's responses are provided.

Comment: Several commenters stated that industry experience confirms that stringent limits on power plant Hg emissions can be readily achieved at lower-than-predicted costs and thus should be adopted nationally through CAA section 112(d)(6). They said that at least 14 states have, for years, enforced state-based limits on power plant Hg emissions, and nearly every one of those states has imposed more stringent emission limits than those proposed in this rulemaking or in the final 2012 MATS Final Rule. The commenters said that these lower emissions limits have resulted in significant and meaningful Hg emission reductions, which have proven to be both achievable and cost-effective.

Some commenters recommended that the EPA revise the Hg limits to levels that are much more stringent than existing or proposed standards for both EGUs firing non-lignite coals and those firing lignite. They claimed that more stringent Hg emission standards are supported by developments in practices, processes, and control technologies. They pointed to a 2021 report by Andover Technology Partners, which details advances in control technologies that support more stringent Hg standards for all coal-fired EGUs.[67] These advances include advanced activated carbon sorbents with higher capture capacity at lower injection rates and carbon sorbents that are tolerant of flue gas species.

Response: The EPA has taken these comments and the referenced information into consideration when establishing the final emission standards. The EPA disagrees that the Agency should, in this final rule, revise the Hg limits for all coal-fired EGUs to levels more stringent than the current or proposed standards. The Agency did not propose in the 2023 Proposal to revise the Hg emission standard for ''not-low-rank coal units'' (*i.e.,* those EGUs that are firing on coals other than lignite) and did not suggest an emission standard for lignite-fired EGUs more stringent than the 1.2 lb/TBtu emission standard that was proposed. However, the EPA will continue to review emission standards and other rule requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If we determine in subsequent CAA section 112(d)(6) technology reviews that further revisions to Hg emission standards (or to standards for other HAP or surrogate pollutants) are warranted, then we will propose revisions at that time. We discuss the rationale for the final emission standards in section V.D. of this preamble and in more detail in the 2024 Technical Memo.

Comment: Several commenters challenged the data that the EPA used in the CAA 112(d)(6) technology review. Commenters stated that the information collected by the EPA via the CAA section 114 request consisted of 17 units each submitting two 1-week periods of data and associated operational data preselected by the EPA, and that only a limited number of the EGUs reported burning only lignite. Other EGUs reported burning primarily refined coal, co-firing with natural gas, and firing or co-firing with large amounts of subbituminous coal (referencing table 7 in the 2023 Proposal). Commenters stated that if the EPA's intent was to assess the Hg control performance of lignite-fired EGUs, then the EGUs evaluated should have burned only lignite, not refined coal, subbituminous coal, or natural gas.

Response: The EPA disagrees with the commenters' argument that the Agency should have only considered emissions and operational data from EGUs that were firing only lignite. The EPA's intent was to evaluate the Hg emission control performance of units that are permitted to burn lignite and are thus subject to a Hg emission standard of 4.0 lb/TBtu. According to fuel use information supplied to EIA on form 923,[68] 13 of 22 EGUs that were designed to burn lignite utilized ''refined coal'' to some extent in 2021, as summarized in table 7 in the 2023 Proposal preamble (88 FR 24878). EIA form 923 does not specify the type of coal that is ''refined'' when reporting boiler or generator fuel use. For the technology review, the EPA assumed that the facilities utilized ''refined lignite,'' as reported in fuel receipts on EIA form 923. In any case, firing of refined lignite or subbituminous coal or co-firing with natural gas or fuel oil are considered to be Hg emission reduction strategies for a unit that is subject to an emission standard of 4.0 lb/TBtu, which was based on the use of lignite as its fuel.

In a related context, in *U.S. Sugar Corp.* v. *EPA,* the D.C. Circuit held that the EPA could not exclude unusually high performing units within a subcategory from the Agency's determination of MACT floor standards for a subcategory pursuant to CAA section 112(d)(3). 830 F.3d 579, 631–32 (D.C. Cir. 2016) (finding ''an unusually high-performing source should be considered[,]'' in determining MACT floors for a subcategory, and that ''its performance suggests that a more stringent MACT standard is appropriate.''). While the technology review at issue here is a separate and distinct analysis from the MACT floor setting requirements at issue in *U.S. Sugar* v. *EPA,* similarly here the EPA finds it is appropriate to consider emissions from all units that are permitted to burn lignite and are therefore subject to the prior Hg emission standard of 4.0 lb/TBtu and are part of the lignite-fired EGU subcategory, for the purposes of determining whether more stringent standards are appropriate under a technology review. However, while the EPA has considered the emissions performance of all units within the lignite-fired EGU subcategory, it is not the performance of units that are firing or co-firing with other non-lignite fuels that provide the strongest basis for the more stringent standard. Rather, the most convincing evidence to support the more stringent standard is that there are EGUs that are permitted to fire lignite—and are only firing lignite—that have demonstrated an ability to meet the more stringent standard of 1.2 lb/TBtu.

Comment: Several commenters claimed that, rather than using actual measured Hg concentrations in lignite that had been provided in the CAA section 114 request responses (and elsewhere), the EPA used Integrated Planning Model (IPM) data to assign inlet Hg concentrations to various lignite-fired EGUs. Some commenters asserted that the actual concentration of Hg in lignite is higher than those assumed by the EPA and that there is considerable variability in the concentration of Hg in the lignite used in these plants. As a result, the commenters claimed, the percent Hg capture needed to achieve the proposed 1.2 lb/TBtu emission standard would be higher than that assumed by the EPA in the 2023 Proposal.

[67] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[68] *https://www.eia.gov/electricity/data/eia923/.*

Response: In the 2023 Proposal, the EPA assumed a Hg inlet concentration (*i.e.,* concentration of Hg in the fuel) that reflected the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the IPM. In response to comments received on the proposal, the EPA has modified the Hg inlet concentration assumptions for each unit to reflect measured Hg concentrations in lignite using information provided by commenters and other sources, including measured Hg concentrations in fuel samples from the Agency's 1998 Information Collection Request (1998 ICR). This is explained in additional detail below in section V.D.1. and in a supporting technical memorandum titled *1998 ICR Coal Data Analysis Summary of Findings.* However, this adjustment in the assumed concentration of Hg in the various fuels did not change the EPA's overall conclusion that there are available controls and improved methods of operation that will allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu.

Comment: Some commenters claimed that the Agency failed to account for compositional differences in lignite as compared to those of other types of coal—especially in comparison to subbituminous coal.

Response: The EPA disagrees with these commenters. In the 2023 Proposal, the EPA emphasized the similarities between lignite and subbituminous coal—especially regarding the fuel properties that most impact the control of Hg. The EPA noted that lignite and subbituminous coal are both low rank coals with low halogen content and explained that the halogen content of the coal—especially chlorine—strongly influences the oxidation state of Hg in the flue gas stream and, thereby, directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. The EPA further noted that the fly ashes from lignite and subbituminous coals tend to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and to the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. Due to the natural alkalinity, subbituminous and lignite fly ashes can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of gaseous elemental Hg vapor (Hg^0). This lack of free halogen in the flue gas challenges the control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs as compared to the Hg control of EGUs firing bituminous coal. The EPA noted in the 2023 Proposal, however, that control strategies and control technologies have been developed and utilized to introduce halogens to the flue gas stream, and that EGUs firing subbituminous coals have been able to meet (and oftentimes emit at emission rates that are considerably lower than) the 1.2 lb/TBtu emission standard in the 2012 MATS Final Rule. Therefore, while the EPA acknowledges that there are differences in the composition of the various coal types, there are available control technologies that allow EGUs firing any of those coal types to achieve an emission standard of 1.2 lb/TBtu. The EPA further notes that North Dakota and Texas lignites are much more similar in composition and in other properties to Wyoming subbituminous coal than either coal type is to eastern bituminous coal. Both lignite and subbituminous coal are lower heating value fuels with high alkaline content and low natural halogen. In contrast, eastern bituminous coals are higher heating value fuels with high natural halogen content and low alkalinity. But while Wyoming subbituminous coal is much more similar to lignite than it is to eastern bituminous coals, EGUs firing subbituminous coal must meet the same Hg emission standard (1.2 lb/TBtu) as EGUs firing bituminous coal. The EPA further acknowledges the differences in sulfur content between subbituminous coal and lignite and its impact is discussed in the following comment summary and response.

Comment: Some commenters claimed that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. The commenters noted that the presence of SO_3 is known to negatively impact the effectiveness of activated carbon for Hg control.

Response: The EPA agrees with the commenters that the Agency did not fully address the potential impacts of SO_3 on the control of Hg from lignite-fired EGUs in the 2023 Proposal. However, in response to these comments, the EPA conducted a more robust evaluation of the impact of SO_3 in the flue gas of lignite-fired EGU and determined that it does not affect our previous determination that there are control technologies and methods of operation that are available to EGUs firing lignite that would allow them to meet a Hg emission standard of 1.2 lb/TBtu—the same emission standard that must be met by EGUs firing all other types of coal. As discussed in more detail below, the EPA determined that there are commercially available advanced ''SO_3 tolerant'' Hg sorbents and other technologies that are specifically designed for Hg capture in high SO_3 flue gas environments. These advanced sorbents allow for capture of Hg in the presence of SO_3 and other challenging flue gas environments at costs that are consistent with the use of conventional pre-treated activated carbon sorbents.[69] The EPA has considered the additional information regarding the role of flue gas SO_3 on Hg control and the information on the availability of advanced ''SO_3 tolerant'' Hg sorbents and other control technologies and finds that this new information does not change the Agency's determination that a Hg emission standard of 1.2 lb/TBtu is achievable for lignite-fired EGUs.

Comment: Several commenters noted the EPA made improper assumptions to reach the conclusion that the revised Hg emissions limit is achievable and claimed that none of the 22 lignite-fired EGUs are currently in compliance with the proposed 1.2 lb/TBtu Hg emission standard and that the EPA has not shown that any EGU that is firing lignite has demonstrated that it can meet the proposed Hg emission standard.

Response: The EPA disagrees with commenters' assertion and maintains that the Agency properly determined that the proposed, more stringent Hg emission standard can be achieved, cost-effectively, using available control technologies and improved methods of operation. Further, the EPA notes that, contrary to commenters' claim, there are, in fact, EGUs firing lignite that have demonstrated an ability to meet the more stringent 1.2 lb/TBtu Hg emission standard. Twin Oaks units 1 and 2 are lignite-fired EGUs operated by Major Oak Power, LLC, and located in Robertson County, Texas. In the 2023 Proposal (see 88 FR 24879 table 8), we showed that 2021 average Hg emission rates for Twin Oaks 1 and 2 (listed in the table as Major Oak #1 and Major Oak #2) were 1.24 lb/TBtu and 1.31 lb/TBtu, respectively, which are emission rates that are just slightly above the final emission limit. Both units at Major Oak have qualified for LEE status for Hg. To demonstrate LEE status for Hg an EGU owner/operator must conduct an initial EPA Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit (PTE) that is less than 10 percent of the applicable Hg emissions limit (for

[69] See Tables 8 and 9 from ''Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants'', Andover Technology Partners (August 2021); available in the rulemaking docket at Docket ID: EPA–HQ–OAR–2018–4583.

lignite-fired EGUs this would be a rate of 0.40 lb/TBtu) *or* less than 29 lb of Hg per year. If an EGU qualifies as a LEE for Hg, then the owner/operator must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. In their most recent compliance reports [70] (dated November 14, 2023), Major Oak Power, LLC, summarized the performance testing. Between August 1 and September 19, 2023, Major Oak Power, LLC, personnel performed a series of performance tests for Hg on Twin Oaks units 1 and 2. The average Hg emissions rate for the 30-boiler operating day performance tests was 1.1 lb/TBtu for unit 1 and 0.91 lb/TBtu for unit 2. The EGUs demonstrated LEE status by showing that each of the units has a Hg PTE of less than 29 lb per year. Further, in LEE demonstration testing for the previous year (2022), Major Oak Power, LLC, found that the average Hg emissions rate for the 30-boiler operating day performance test was 0.86 lb/TBtu for unit 1 and 0.63 lb/TBtu for unit 2.

In the 2023 LEE demonstration compliance report, Twin Oaks unit 1 was described as a fluidized bed boiler that combusts lignite and is equipped with fluidized bed limestone (FBL) injection for SO_2 control, selective non-catalytic reduction (SNCR) for control of nitrogen oxides (NO_X), and a baghouse (FF) for PM control. In addition, unit 1 has an untreated activated carbon injection (UPAC) system as well as a brominated powdered activated carbon (BPAC) injection system for absorbing vapor phase Hg in the effluent upstream of the baghouse. Twin Oaks unit 2 is described in the same way.

Similarly, Red Hills units 1 and 2, located in Choctaw County, Mississippi,[71] also demonstrated 2021 annual emission rates while firing lignite from an adjacent mine of 1.33 lb/TBtu and 1.35 lb/TBtu, which are reasonably close to the proposed Hg emission standard of 1.2 lb/TBtu to demonstrate achievability. In 2022, average Hg emission rates for Red Hills unit 1 and unit 2, again while firing Mississippi lignite, were 1.73 lb/TBtu and 1.75 lb/TBtu, respectively. The EPA also notes that, as shown below in table 5, lignite mined in Mississippi has the highest average Hg content—as compared to lignites mined in Texas and North Dakota.

The performance of Twin Oaks units 1 and 2 and Red Hills Generating Facility units 1 and 2 clearly demonstrate the achievability of the proposed 1.2 lb/TBtu emission standard by lignite-fired EGUs. However, even if there were no lignite-fired EGUs that are meeting (or have demonstrated an ability to meet) the more stringent Hg emission standard, that would not mean that the more stringent emission standard was not achievable. Most Hg control technologies are ''dial up'' technologies—for example, sorbents or chemical additives have injection rates that can be ''dialed'' up or down to achieve a desired Hg emission rate. In response to the EPA's 2022 CAA section 114 information request, some responding owners/operators indicated that sorbent injection rates were set to maintain a Hg emission rate below the 4.0 lb/TBtu emission limit. In some instances, operators of EGUs reported that they were not injecting any Hg sorbent and were able to meet the less stringent emission standard. Most units that are permitted to meet a Hg emission standard of 4.0 lb/TBtu have no reason to ''over control'' since doing so by injecting more sorbent would increase their operating costs. So, it is unsurprising that many units that are permitted to fire lignite have reported Hg emission rates between 3.0 and 4.0 lb/TBtu.

While most lignite-fired EGUs have no reason to ''over control'' beyond their permitted emission standard of 4.0 lb/TBtu, Twin Oaks units 1 and 2 do have such motivation. As mentioned earlier, those sources have achieved LEE status for Hg (by demonstrating a Hg PTE of less than 29 lb/yr) and they must conduct annual performance tests to show that the units continue to qualify. According to calculations provided in their annual LEE certification, to maintain LEE status, the units could emit no more than 1.79 lb/TBtu and maintain a PTE of less than 29 lb/TBtu. So, the facilities are motivated to over control beyond 1.79 lb/TBtu (which, as described earlier in this preamble, they have consistently done).

Comment: To highlight the difference in the ability of lignite-fired and subbituminous-fired EGUs to control Hg, one commenter created a table to show a comparison between the Big Stone Plant (an EGU located in South Dakota firing subbituminous coal) and Coyote Station (an EGU located in North Dakota firing lignite). Additionally, the commenter included figures showing rolling 30-boiler operating day average Hg emission rates and the daily average ACI feed rates for Big Stone and Coyote EGUs for years 2021–2022. Their table showed that Big Stone and Coyote are similarly configured plants that utilize the same halogenated ACI for Hg control. The commenters said, however, that Coyote Station's average sorbent feed rate on a lb per million actual cubic feet (lb/MMacf) basis is more than three times higher than that for Big Stone, yet Coyote Station's average Hg emissions on a lb/TBtu basis are more than five times higher than Big Stone.

Response: The EPA agrees that the Big Stone and Coyote Station units referenced by the commenter are similarly sized and configured EGUs, with the Big Stone unit in South Dakota firing subbituminous coal and the Coyote Station unit in North Dakota firing lignite. However, there are several features of the respective units that can have an impact on the control of Hg. First, and perhaps the most significant, the Big Stone unit has a selective catalytic reduction (SCR) system installed for control of NOx. The presence of an SCR is known to enhance the control of Hg—especially in the presence of chemical additives. The Coyote Station EGU does not have an installed SCR. Further, both EGUs have a dry FGD scrubber and FF baghouse installed for SO_2/acid gas and fPM control. The average sulfur content of North Dakota lignite is approximately 2.5 times greater than that of Wyoming subbituminous coal. However, the average SO_2 emissions from the Coyote Station EGU (0.89 lb/MMBtu) were approximately 10 times higher than the SO_2 emissions from the Big Stone EGU (0.09 lb/MMBtu). The Big Stone dry scrubber/FF was installed in 2015; while the dry scrubber/FF at Coyote Station was installed in 1981—approximately 31 years earlier. So, considering the presence of an SCR—which is known to enhance Hg control—and newer and better performing downstream controls, it is unsurprising that there are differences in the control of Hg at the two EGUs. In addition, since the Coyote Station has been subject to a Hg emission standard of 4.0 lb/TBtu, there would be no reason for the operators to further optimize its control system to achieve a lower emission rate. And, as numerous commenters noted, the Hg content of North Dakota is higher than that of Wyoming subbituminous coal.

Comment: Some commenters claimed that the EPA has not adequately justified a reversal in the previous policy to establish a separate subcategory for lignite-fired EGUs.

[70] See page 1–1 of the 2023 Compliance Reports for Twin Oaks 1 and 2 available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[71] Choctaw Generation LP leases and operates the Red Hills Power Plant. The plant supplies electricity to the Tennessee Valley Authority (TVA) under a 30-year power purchase agreement. The lignite output from the adjacent mine is 100 percent dedicated to the power plant. *https://www.purenergyllc.com/projects/choctaw-generation-lp-red-hills-power-plant/#page-content.*

Response: In developing the 2012 Final MATS Rule, the EPA examined the EGUs in the top performing 12 percent of sources for which the Agency had Hg emissions data. In examining that data, the EPA observed that there were no lignite-fired EGUs among the top performing 12 percent of sources for Hg emissions. The EPA then determined that this indicated that there is a difference in the Hg emissions from lignite-fired EGUs when compared to the Hg emissions from EGUs firing other coal types (that were represented among the top performing 12 percent). That determination was not based on any unique property or characteristic of lignite—only on the observation that there were no lignite-fired EGUs among the best performing 12 percent of sources (for which the EPA had Hg emissions data). In fact, as noted in the preamble for the 2012 Final MATS Rule, the EPA ''believed at proposal that the boiler size was the cause of the different Hg emissions characteristics.'' See 77 FR 9378.

The EPA ultimately concluded that it is appropriate to continue to base the subcategory definition, at least in part, on whether the EGUs were ''designed to burn and, in fact, did burn low rank-virgin coal'' (*i.e.,* lignite), but that it is not appropriate to continue to use the boiler size criteria (*i.e.,* the height-to-depth ratio). However, the EPA ultimately finalized the ''unit designed for low rank virgin coal'' subcategory based on the characteristics of the EGU—not on the properties of the fuel. ''We are finalizing that the EGU is considered to be in the ''unit designed for low rank virgin coal'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is designed to burn and is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.'' See 77 FR 9369.

While, in the 2012 MATS Final Rule, the EPA based the lignite-fired EGU subcategory on the design and operation of the EGUs, the EPA did not attribute the observed differences in Hg emissions to any unique characteristic(s) of lignite. As the EPA clearly noted in the 2023 Proposal, there are, in fact, characteristics of lignite that make the control of Hg more challenging. These include the low natural halogen content, the high alkalinity of the fly ash, the sulfur content, the relatively higher Hg content, and the relatively higher variability of Hg content. However, as the EPA has explained, these characteristics that make the control of Hg more challenging are also found in non-lignite fuels. Subbituminous coals also have low natural halogen content and high fly ash alkalinity. Eastern and central bituminous coals also have high sulfur content. Bituminous and anthracitic waste coals (coal refuse) have very high and variable Hg content. EGUs firing any of these non-lignite coals have been subject to—and have demonstrated compliance with—the more stringent Hg emission standard of 1.2 lb/TBtu.

The EPA has found it appropriate to reverse the previous policy because the decision to subcategorize ''units designed for low rank virgin coal'' in the 2012 MATS Final Rule was based a determination that there were differences in Hg emissions from lignite-fired EGUs as compared to EGUs firing non-lignite coals. That perceived difference was based on an observation that there were no lignite-fired EGUs in the top performing 12 percent of EGUs for which the Agency had Hg emissions data and on an assumption that the perceived difference in emissions was somehow related to the design and operation of the EGU. The EPA is unaware of any distinguishing features of EGUs that were designed to burn lignite that would impact the emissions of Hg. Further, the EPA does not now view the fact that there were no lignite-fired EGUs in the population of the best-performing 12 percent of EGUs for which the Agency had Hg emissions data to represent a ''difference in emissions.''

But, on re-examination of the data, the EPA has concluded that the Hg emissions from the 2010 ICR for the lignite-fired EGUs were not clearly distinctive from the Hg emissions from EGUs firing non-lignite coal. In setting the emission standards for the 2012 MATS Final Rule, the EPA had available and useable Hg emissions data from nearly 400 coal-fired EGUs (out of the 1,091 total coal-fired EGUs operating at that time). However, the EPA only had available and useable data from nine lignite-fired EGUs with reported floor Hg emissions ranging from 1.0 to 10.9 lb/TBtu. But these were not outlier emission rates. EGUs firing bituminous coal reported Hg emissions as high as 30.0 lb/TBtu; and those firing subbituminous coal reported Hg emissions as high as 9.2 lb/TBtu.

D. What is the rationale for our final approach and decisions for the lignite-fired EGU Hg standard?

In the 2023 Proposal, the EPA proposed to determine that there are developments in available control technologies and methods of operation that would allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu—the same Hg emission standard that must be met by coal-fired EGUs firing non-lignite coals (*e.g.,* anthracite, bituminous coal, subbituminous coal, coal refuse, *etc.*). After consideration of public comments received on the proposed revision of the Hg emission standard, the EPA continues to find that the evidence supports that there are commercially available control technologies and improved methods of operation that allow lignite-fired EGUs to meet the more stringent Hg emission standard that the EPA proposed. As noted above, lignite-fired EGUs also comprise some of the largest sources of Hg emissions within this source category and are responsible for a disproportionate share of Hg emissions relative to their generation. While previous EPA assessments have shown that current modeled exposures [of Hg] are well below the reference dose (RfD), we conclude that further reductions of Hg emissions from lignite-fired EGUs covered in this final action should further reduce exposures including for the subsistence fisher sub-population. This anticipated exposure is of particular importance to children, infants, and the developing fetus given the developmental neurotoxicity of Hg. Therefore, in this final action, the EPA is revising the Hg emission standard for lignite-fired EGUs from the 4.0 lb/TBtu standard that was finalized in the 2012 MATS Final Rule to the more stringent emission standard of 1.2 lb/TBtu, as proposed. The rationale for the Agency's final determination is provided below.

In this final rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the Hg emission standard for lignite-fired EGUs. As discussed in section II.D. above, the 2020 Technology Review did not evaluate the current performance of emission reduction control equipment and strategies at existing lignite-fired EGUs. Nor did the 2020 Technology Review specifically address the discrepancy between Hg emitted from lignite-fired EGUs and non-lignite coal-fired EGUs or consider the improved performance of injected sorbents or chemical additives, or the development of SO_3-tolerant sorbents. Based on the EPA's review in this rulemaking which considered such information, the Agency determined that there are available control technologies that allow EGUs firing lignite to achieve an emission standard of 1.2 lb/TBtu, consistent with the Hg emission standard required for non-lignite coal-fired EGUs, which the EPA is finalizing pursuant to its CAA section 112(d)(6) authority.

1. Mercury Content of Lignite

For analyses supporting the proposal, the EPA assumed ''Hg Inlet'' levels (*i.e.,* Hg concentration in inlet fuel) that are consistent with those assumed in the Agency's power sector model (IPM) and then adjusted accordingly to reflect the 2021 fuel blend for each unit. Several commenters indicated that the Hg content of lignite fuels is much higher and has greater variability than the EPA assumed.

To support the development of the NESHAP for the Coal- and Oil-Fired EGU source category, the Agency conducted a 2-year data collection effort which was initiated in 1998 and completed in 2000 (1998 ICR). The ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly owned utility companies, federal power agencies, rural electric cooperatives, and investor-owned utility generating companies; (2) obtaining accurate information on the amount of Hg contained in the as-fired coal used by each electric utility steam generating unit with a capacity greater than 25 MW electric, as well as accurate information on the total amount of coal burned by each such unit; and (3) obtaining data by coal sampling and stack testing at selected units to characterize Hg reductions from representative unit configurations.

The ICR captured the origin of the coal burned, and thus provided a pathway for linking emission properties to coal basins. The 1998–2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, Hg content, ash content, chlorine content, and other characteristics of coal burned at coal-fired utility boilers greater than 25 MW.

Annual fuel characteristics and delivery data reported on EIA form 923 also provide continual data points on coal heat content, sulfur content, and geographic origin, which are used as a check against characteristics initially identified through the 1998 ICR.

For this final rule, the EPA re-evaluated the 1998 ICR data.[72] Specifically, the EPA evaluated the coal Hg data to characterize the Hg content of lignite, which is mined in North Dakota, Texas, and Mississippi, and to characterize by seam and by coal delivered to a specific plant.[73] The results are presented as a range of Hg content of the lignites as well as the mean and median Hg content. The EPA also compared the fuel characteristics of lignites mined in North Dakota, Texas, and Mississippi against coals mined in Wyoming (subbituminous coal), Pennsylvania (mostly upper Appalachian bituminous coal), and Kentucky (mostly lower Appalachian bituminous coal). The Agency also included in the re-evaluation, coal analyses that were submitted in public comments by North American Coal (NA Coal). In addition to the Hg content, the analysis included the heating value and the sulfur, chlorine, and ash content for each coal that is characterized.

The analysis showed that lignite mined in North Dakota had a mean Hg content of 9.7 lb/TBtu, a median Hg content of 8.5 lb/TBtu, and a Hg content range of 2.2 to 62.1 lb/TBtu. Other characteristics of North Dakota lignite include an average heating value (dry basis) of 10,573 Btu/lb, an average sulfur content of 1.19 percent, an average ash content of 13.5 percent, and an average chlorine content of 133 parts per million (ppm). In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in North Dakota to 9.7 lb/TBtu versus the 7.81 lb/TBtu assumed in the 2023 Proposal.

Similarly, the analysis showed that lignite mined in Texas had a mean and median Hg content of 25.0 lb/TBtu and 23.8 lb/TBtu, respectively, and a Hg content range from 0.7 to 92.0 lb/TBtu. Other characteristics include an average heating value (dry basis) of 9,487 Btu/lb, an average sulfur content of 1.42 percent, an average ash content of 24.6 percent, and an average chlorine content of 233 ppm. In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in Texas to 25.0 lb/TBtu versus the range of 14.65 to 14.88 lb/TBtu that was assumed for the 2023 Proposal.

Lignite mined in Mississippi had the highest mean Hg content at 34.3 lb/TBtu and the second highest median Hg emissions rate, 30.1 lb/TBtu. The Hg content ranged from 3.6 to 91.2 lb/TBtu. Lignite from Mississippi had an average heating value (dry basis) of 5,049 Btu/lb and a sulfur content of 0.58 percent. In response to comments submitted on the 2023 Proposal, for analyses supporting this final action, the EPA assumed a Hg content of 34.3 lb/TBtu for lignite mined in Mississippi versus the 12.44 lb/TBtu assumed for the proposal.

The EPA 1998 ICR dataset did not contain information on lignite from Mississippi, which resulted in a smaller number of available data points (227 in Mississippi lignite versus 864 for North Dakota lignite and 943 for Texas lignite). Table 5 of this document more fully presents the characteristics of lignite from North Dakota, Texas, and Mississippi.

[72] Technical Support Document ''*1998 ICR Coal Data Analysis Summary of Findings*'' available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[73] In 2022, over 99 percent of all lignite was mined in North Dakota (56.2 percent), Texas (35.9 percent), and Mississippi (7.1 percent). Small amounts (less than 1 percent) of lignite were also mined in Louisiana and Montana. See Table 6. ''Coal Production and Number of Mines by State and Coal Rank'' from EIA Annual Coal Report, available at *https://www.eia.gov/coal/annual/.*

Table 5. Characteristics of Lignite mined in North Dakota, Texas, and Mississippi from the EPA 1998 ICR Dataset

	North Dakota	Texas	Mississippi
Number of data points	864	943	227
Range of Hg content (lb/TBtu)	2.2 – 62.1	0.7 – 92.0	3.6 – 91.2
Mean Hg content (lb/TBtu)	9.7	25.0	34.3
Median Hg content (lb/TBtu)	8.5	23.8	30.1
Heating value average (Btu/lb, dry)	10,573	9,486	5,049
Sulfur content average (%, dry)	1.12	1.42	0.58
Ash content average (%, dry)	13.54	24.60	N/A
Chlorine content average (ppm, dry)	133	232	N/A

Coals mined in Kentucky, Pennsylvania, and Wyoming were also analyzed for comparison. The types of coal (all non-lignite) included bituminous, bituminous-high sulfur, bituminous-low sulfur, subbituminous, anthracite, waste anthracite, waste bituminous, and petroleum coke. Bituminous coal accounted for 92 percent of the data points from Kentucky and 75 percent of the data points from Pennsylvania. Subbituminous coal accounted for 96 percent of the data points from Wyoming.

Bituminous coals from Kentucky had a mean Hg emissions content of 7.2 lb/TBtu (ranging from 0.7 to 47.4 lb/TBtu), an average heating value (dry basis) of 13,216 Btu/lb, an average sulfur content of 1.43 percent, an average ash content of 10.69 percent, and an average chlorine content of 1,086 ppm.

Bituminous coals from Pennsylvania had a mean Hg emissions rate of 14.5 lb/TBtu (ranging from 0.1 to 86.7 lb/TBtu), an average heating value (dry basis) of 13,635 Btu/lb, an average sulfur content of 1.88 percent, an average ash content of 10.56 percent, and an average chlorine content of 1,050 ppm.

Subbituminous coals from Wyoming had a mean Hg rate of 5.8 lb/TBtu, an average heating value (dry basis) of 12,008 Btu/lb, an average sulfur content of 0.44 percent, an average ash content of 7.19 percent, and an average chlorine content of 127 ppm. Table 6 of this document shows the characteristics of bituminous coal from Kentucky and Pennsylvania and subbituminous coal from Wyoming.

Table 6. Characteristics of Bituminous and Subbituminous Coals mined in Kentucky, Pennsylvania, and Wyoming from the EPA 1998 ICR Dataset

	Kentucky (Bituminous)	Pennsylvania (Bituminous)	Wyoming (Subbituminous)
Number of data points	5,340	3,072	6,467
Range of Hg content (lb/TBtu)	0.7 – 47.4	0.1 – 86.7	0.7 – 40.7
Mean Hg content (lb/TBtu)	7.2	14.5	5.8
Median Hg content (lb/TBtu)	6.7	9.7	2.4
Heating value average (Btu/lb, dry)	13,216	13,635	12,008
Sulfur content average (%, dry)	1.43	1.88	0.44
Ash content average (%, dry)	10.69	10.56	7.19
Chlorine content average (ppm, dry)	1,086	1,050	127

Several commenters claimed that one of the factors that contributes to the challenge of controlling Hg emissions from EGUs firing lignite is the variability of the Hg content in lignite. However, as can be seen in table 5 and table 6 of this document, all coal types examined by the EPA contain a variable content of Hg. The compliance demonstration requirements in the 2012 MATS Final Rule were designed to accommodate the variability of Hg in coal by requiring compliance with the respective Hg emission standards over a 30-operating-day rolling average period. When examining the Hg emissions for EGUs firing on the various coal types (including those firing Wyoming subbituminous coal, which has the lowest mean and median Hg content and the narrowest range of Hg content), daily emissions often exceed the applicable emission standard (sometimes considerably). However, averaging emissions over a rolling 30-operating-day period effectively dampens the impacts of fuel Hg content variability. For example, in figure 1 (a graph) of this document, the 2022 Hg emissions from Dave Johnston unit BW41, a unit firing subbituminous coal, are shown. The graph shows both the daily Hg emissions and the 30-operating-day rolling average Hg emissions. As can be seen in the graph, the daily Hg emissions very often exceed the 1.2 lb/TBtu emission rate; however, the 30-operating-day rolling average is consistently below the emission limit (the annual average emission rate is 0.9 lb/TBtu).

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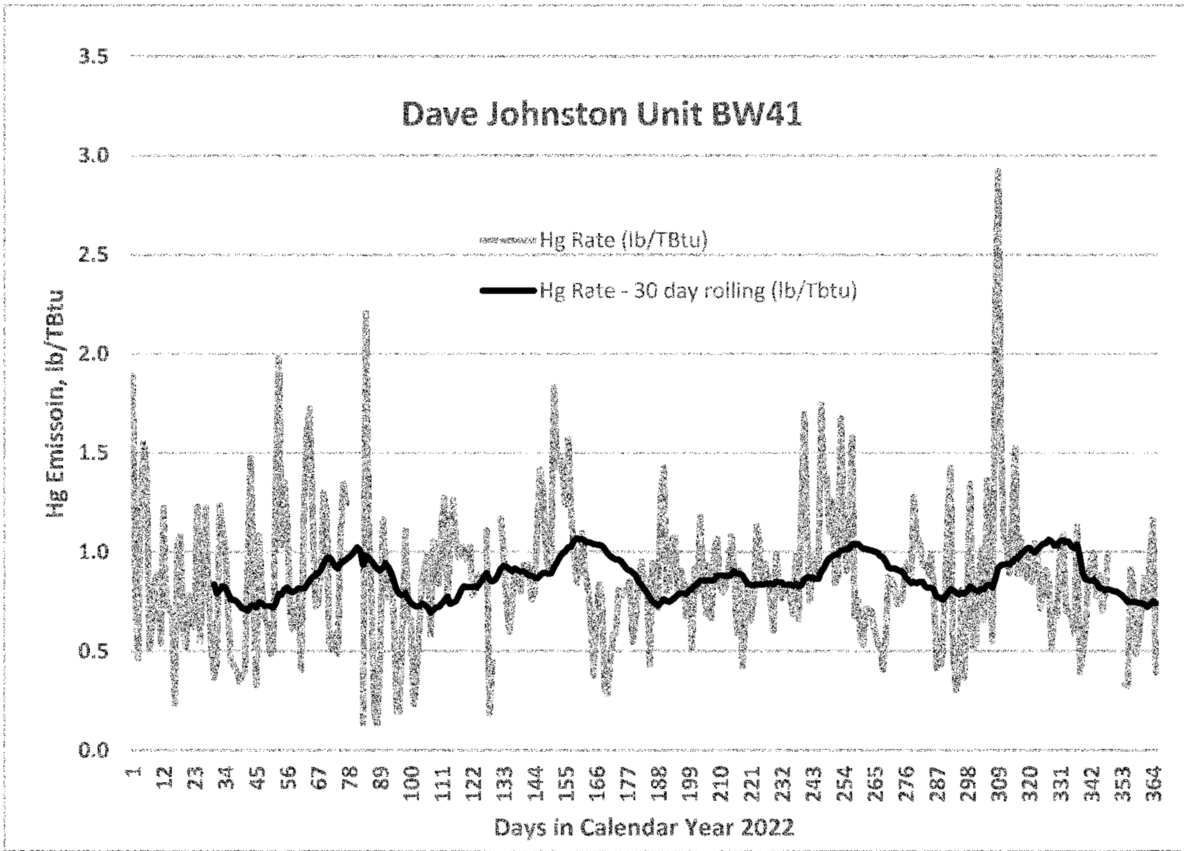

Figure 1. 2022 Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu)

From Dave Johnston Unit BW41, a subbituminous-fired EGU in Wyoming.

A similar effect can be seen with the 2022 daily and 30-operating-day rolling average Hg emissions from Leland Olds unit 1, an EGU firing North Dakota lignite, shown in figure 2 of this document.

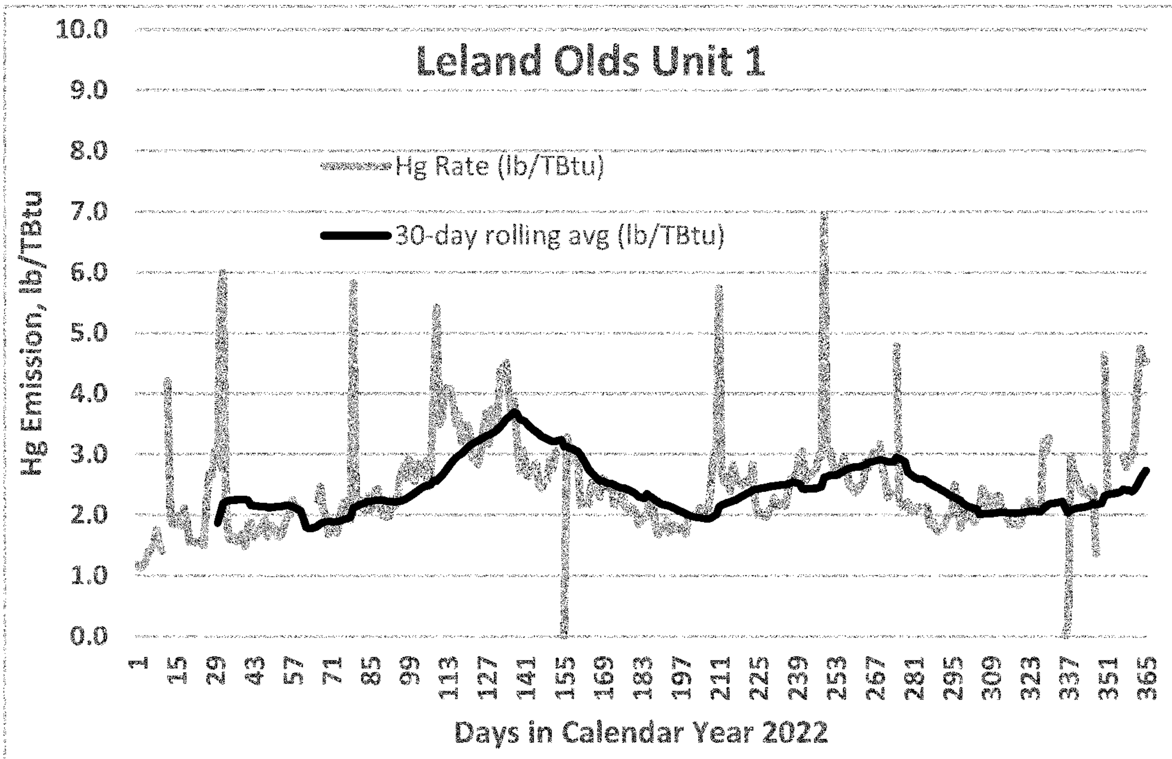

Figure 2. Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu) from Leland Olds Unit 1, lignite-fired EGU in North Dakota.

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As with the EGU firing subbituminous coal, the daily Hg emissions very often exceed the emission limit (in this case 4.0 lb/TBtu); however, the 30-operating-day rolling average is consistently below the applicable emission limit (the 2022 annual average emission rate for Leland Olds unit 1 is 2.3 lb/TBtu).

2. The Impact of Halogen Content of Lignite on Hg Control

In the 2023 Proposal, the EPA explained that during combustion of coal, the Hg contained in the coal is volatilized and converted to Hg^0 vapor in the high-temperature regions of the boiler. Hg^0 vapor is difficult to capture because it is typically nonreactive and insoluble in aqueous solutions. However, under certain conditions, the Hg^0 vapor in the flue gas can be oxidized to divalent Hg (Hg^{2+}). The Hg^{2+} can bind to the surface of solid particles (*e.g.,* fly ash, injected sorbents) in the flue gas stream, often referred to as ''particulate bound Hg'' (Hg_p) and be removed in a downstream PM control device. Certain oxidized Hg compounds that are water soluble may be further removed in a downstream wet scrubber. The presence of chlorine in gas-phase equilibrium favors the formation of mercuric chloride ($HgCl_2$) at flue gas cleaning temperatures. However, Hg^0 oxidation reactions are kinetically limited as the flue gas cools, and as a result Hg may enter the flue gas cleaning device(s) as a mixture of Hg^0, Hg^{2+} compounds, and Hg_p.

This partitioning into various species of Hg has considerable influence on selection of Hg control approaches. In tables 5 and 6 of this document, the chlorine content of bituminous coals mined in Kentucky and Pennsylvania averaged 1,086 ppm and 1,050 ppm, respectively. In comparison, the average chlorine content of Wyoming subbituminous coal is 127 ppm; while the chlorine contents of lignite mined in North Dakota and Texas are 133 ppm and 232 ppm, respectively. In general, because of the presence of higher amounts of halogen (especially chlorine) in bituminous coals, most of the Hg in the flue gas from bituminous coal-fired boilers is in the form of Hg^{2+} compounds, typically $HgCl_2$, and is more easily captured in downstream control equipment. Conversely, both subbituminous coal and lignite have lower natural halogen content compared to that of bituminous coals, and the Hg in the flue gas from boilers firing those fuels tends to be in the form of Hg^0 and is more challenging to control in downstream control equipment.

While some bituminous coal-fired EGUs require the use of additional Hg-specific control technology, such as injection of a sorbent or chemical additive, to supplement the control that these units already achieve from criteria pollutant control equipment, these Hg-specific control technologies are often required as part of the Hg emission reduction strategy at EGUs that are firing subbituminous coal or lignite. As described above, the Hg in the flue gas for EGUs firing subbituminous coal or lignite tends to be in the nonreactive Hg^0 vapor phase due to lack of available free halogen to promote the oxidation reaction. To alleviate this challenge, activated carbon and other sorbent providers and control technology vendors have developed methods to introduce halogen into the flue gas to improve the control of Hg emissions from EGUs firing subbituminous coal and lignite. This is primarily through the injection of pre-halogenated (often pre-brominated) activated carbon sorbents or through the injections of halogen-containing chemical additives along with conventional sorbents. In the

2022 CAA section 114 information collection, almost all the lignite-fired units reported use of some sort of halogen additive or injection as part of their Hg control strategy by using refined coal (which typically has added halogen), bromide or chloride chemical additives, pre-halogenated sorbents, and/or oxidizing agents. Again, low chlorine content in the fuel is a challenge that is faced by EGUs firing either subbituminous coals or lignite, and EGUs firing subbituminous coal have been subject to a Hg emission standard of 1.2 lb/TBtu since the MATS rule was finalized in 2012.

3. The Impact of SO_3 on Hg Control

Some commenters noted that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. As shown in table 5 and table 6 of this document, while the halogen content of subbituminous coal and lignite is similar, the average sulfur content of lignite is more like that of bituminous coal mined in Kentucky and Pennsylvania.

During combustion, most of the sulfur in coal is oxidized into SO_2, and only a small portion is further oxidized to SO_3 in the boiler. In response to environmental requirements, many EGUs have installed SCR systems for NO_X control and FGD systems for SO_2 control. One potential consequence of an SCR retrofit is an increase in the amount of SO_3 in the flue gas downstream of the SCR due to catalytic oxidation of SO_2. Fly ash and condensed SO_3 are the major components of flue gas that contribute to the opacity of a coal plant's stack emissions and the potential to create a visible sulfuric acid ''blue plume.'' In addition, higher SO_3 levels can adversely affect many aspects of plant operation and performance, including corrosion of downstream equipment and fouling of the air preheater (APH). This is primarily an issue faced by EGUs firing bituminous coal. EGUs fueled by subbituminous coal and lignite do not typically have the same problem with blue plume formation. Of the EGUs that are designed to fire lignite, only Oak Grove units 1 and 2, located in Texas, have an installed SCR for NO_X control. Several lignite-fired EGUs utilize SNCR systems for NO_X control, which are less effective for NO_X control as compared to SCR systems. Several commenters claimed that SCR is not a viable NO_X control technology for EGUs firing North Dakota lignite because of catalyst fouling from the high sodium content of the fuel and resulting fly ash.

Coal fly ash is typically classified as acidic (pH less than 7.0), mildly alkaline (pH greater than 7.0 to 9.0), or strongly alkaline (pH greater than 9.0). The pH of the fly ash is usually determined by the calcium/sulfur ratio and the amount of halogen. The ash from bituminous coals tends to be acidic due to the relatively higher sulfur and halogen content and the glassy (nonreactive) nature of the calcium present in the ash. Conversely, the ash from subbituminous coals and lignite tends to be more alkaline due to the lower amounts of sulfur and halogen and a more alkaline and reactive (non-glassy) form of calcium—and, as noted by commenters—the presence of sodium compounds in the ash. The natural alkalinity of the subbituminous and lignite fly ash may effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0. However, the natural alkalinity also helps to minimize the impact of SO_3, because a common control strategy for SO_3 is the injection of alkaline sorbents (dry sorbent injection, DSI).

Still, as commenters correctly noted, the presence of SO_3 in the flue gas stream is also known to negatively impact the effectiveness of sorbent injection for Hg control. This impact has been known for some time, and control technology researchers and vendors have developed effective controls and strategies to minimize the impact of SO_3.[74] As noted above, coal-fired EGUs utilizing bituminous coal—which also experience significant rates of SO_3 formation in the flue gas stream—have also successfully demonstrated the application of Hg control technologies to meet a standard of 1.2 lb/TBtu.

The AECOM patented SBS Injection™ (''sodium-based solution'') technology has been developed for control of SO_3, and co-control of Hg has also been demonstrated. A sodium-based solution is injected into the flue gas, typically ahead of the APH or, if present, the SCR. By removing SO_3 prior to these devices, many of the adverse effects of SO_3 can be successfully mitigated. AECOM has more recently introduced their patented HBS Injection™ technology for effective Hg oxidation and control.[75] This new process injects halogen salt solutions into the flue gas, which react in-situ to form halogen species that effectively oxidize Hg. The HBS Injection™ can be co-injected with the SBS Injection™ for effective SO_3 control and Hg oxidation/control.

Other vendors also offer technologies to mitigate the impact of SO_3 on Hg control from coal combustion flue gas streams. For example, Calgon Carbon offers their ''sulfur tolerant'' Fluepac ST, which is a brominated powdered activated carbon specially formulated to enhance Hg capture in flue gas treatment applications with elevated levels of SO_3.[76] In testing in a bituminous coal combustion flue gas stream containing greater than 10 ppm SO_3, the Fluepac ST was able to achieve greater than 90 percent Hg control at injection rates of a third or less as compared to injection rates using the standard brominated sorbent.

Babcock & Wilcox (B&W) offers dry sorbent injection systems that remove SO_3 before the point of activated carbon sorbent injection to mitigate the impact of SO_3.[77] Midwest Energy Emissions Corporation (ME_2C) offers ''high-grade sorbent enhancement additives—injected into the boiler in minimal amounts'' that work in conjunction with proprietary sorbent products to ensure maximum Hg capture. ME_2C claims that their Hg control additives and proprietary sorbent products are ''high-sulfur-tolerant and SO_3-tolerant sorbents.''[78]

Cabot Norit Activated Carbon is the largest producer of powdered activated carbon worldwide.[79] Cabot Norit offers different grades of their DARCO® powdered activated carbon (PAC) for Hg removal at power plants. These grades include non-impregnated PAC which are ideal when most of the Hg is in the oxidized state; impregnated PAC for removing oxidized and Hg^0 from flue gas; special impregnated PAC used in conjunction with DSI systems (for control of acid gases); and special impregnated ''sulfur resistant'' PAC for flue gases that contains higher concentrations of acidic gases like SO_3.

[74] The mention of specific products by name does not imply endorsement by the EPA. The EPA does not endorse or promote any particular control technology. The EPA mentions specific product names here to emphasize the broad range of products and vendors offering sulfur tolerant Hg control technologies.

[75] *https://www.aecom.com/wp-content/uploads/2019/07/10_EUEC_P_PT_Brochure_HBS_InjectionTechnology_20160226_singles.pdf.*

[76] *https://www.calgoncarbon.com/app/uploads/DS-FLUEST15-EIN-E1.pdf.*

[77] *https://www.babcock.com/assets/PDF-Downloads/Emissions-Control/E101-3200-Mercury-and-HAPs-Emissions-Control-Brochure-Babcock-Wilcox.pdf.*

[78] ME2C 2016 Corporate Brochure, available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[79] *https://norit.com/application/power-steel-cement/power-plants.*

Similarly, ADA–ES offers FastPAC™ Platinum 80,[80] an activated carbon sorbent that was specifically engineered for SO_3 tolerance and for use in applications where SO_3 levels are high. So, owner/operators of lignite-fired EGUs can choose from a range of technologies and technology providers that offer Hg control options in the presence of SO_3. The EPA also notes that SO_3 is more often an issue with EGUs firing eastern bituminous coal—as those coals typically have higher sulfur content and lower ash alkalinity. Those bituminous coal-fired EGUs are subject to—and have demonstrated compliance with—an emission standard of 1.2 lb/TBtu.

[80] *https://www.advancedemissionssolutions.com/ADES-Investors/ada-products-and-services/default.aspx.*

4. Cost Considerations for the More Stringent Hg Emission Standard

From the 2022 CAA section 114 information survey, most lignite-fired EGUs utilized a control strategy that included sorbent injection coupled with chemical additives (usually halogens). In the beyond-the-floor analysis in the 2012 MATS Final Rule, we noted that the results from various demonstration projects suggested that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbents at an injection rate of 2.0 lb/MMacf (*i.e.,* 2.0 pounds of sorbent injected per million actual cubic feet of flue gas) for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. As shown in table 7 of this document, all units (in 2022) would have needed to control their Hg emissions to 95 percent or less to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the final, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule.

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Table 7. Measured Hg Emissions and Estimated Control Performance of Lignite-Fired EGUs in 2022

EGU	Estimated 2022 Hg Inlet[81] (lb/TBtu)	Estimated Hg Control (%) at 4.0 lb/TBtu	Estimated Hg Control (%) at 1.2 lb/TBtu	2022 Measured Hg Emissions (lb/TBtu)	Estimated 2022 Hg Control (%)
North Dakota EGUs					
Antelope Valley 1	11.2	64.4	89.3	3.03	73.0
Antelope Valley 2	11.2	64.4	89.3	3.00	73.3
Coal Creek 1	9.7	58.7	87.6	3.43	64.6
Coal Creek 2	9.7	58.7	87.6	3.87	60.1
Coyote 1	9.7	58.6	87.6	2.28	76.4
Leland Olds 1	11.3	64.5	87.6	2.34	79.3
Leland Olds 2	11.3	64.5	87.6	3.10	72.5
Milton R Young 1	9.7	58.6	87.6	3.02	68.8
Milton R Young 2	9.7	58.6	87.6	3.00	69.0
Spiritwood Station 1	9.2	56.5	87.0	2.14	76.8
Texas and Mississippi EGUs					
Limestone 1*	5.8	30.7	79.2	0.78	86.5
Limestone 2*	5.8	30.7	79.2	0.85	85.3
Major Oak Power 1	24.9	84.0	95.2	0.86	96.5
Major Oak Power 2	24.9	84.0	95.2	0.63	97.5
Martin Lake 1*	5.8	31.0	79.3	1.53	73.6
Martin Lake 2*	5.8	31.0	79.3	2.50	56.9
Martin Lake 3*	5.8	31.0	79.3	2.36	59.3
Oak Grove 1	24.8	83.9	95.2	2.53	89.8
Oak Grove 2	24.8	83.9	95.2	2.23	91.0
San Miguel 1	28.9	86.2	95.9	3.03	89.5
Red Hills 1	22.9	82.6	94.8	1.73	92.5
Red Hills 2	22.9	82.6	94.8	1.75	92.4

* These units, which are permitted to fire lignite, utilized primarily subbituminous coal in 2022.

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To determinethe cost effectiveness of that strategy, we calculated the cost per lb of Hg controlled for a model 800 MW lignite-fired EGU, as described in the 2024 Technical Memo. We calculated the cost of injecting brominated activated carbon sorbent at injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule (*i.e.,* 2.0 lb/MMacf and 3.0 lb/MMacf) and at a larger injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu. We also calculated the incremental cost to meet the more stringent emission rate of 1.2 lb/TBtu versus the cost to meet an emission rate of 4.0 lb/TBtu using non-brominated activated carbon sorbent at an emission rate of 2.5 lb/MMacf. For an 800 MW lignite-fired EGU, the cost effectiveness of using the brominated carbon sorbent at an injection rate of 3.0 lb/MMacf was $3,050 per lb of Hg removed while the incremental cost effectiveness was $10,895 per incremental lb of Hg removed at a brominated activated carbon injection rate of 3.0 lb/MMacf. The cost effectiveness of using the brominated carbon sorbent at an injection rate of 5.0 lb/MMacf was $5,083 per lb of Hg removed while the incremental cost effectiveness was $28,176 per incremental lb of Hg removed. The actual cost effectiveness is likely lower than either of these estimates as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (from the 2022 CAA section 114 information collection, the Oak Grove units were injecting less than 0.5 lb/MMacf) and is either well below or reasonably consistent with the cost effectiveness that the EPA has found to

[81] Estimated Hg inlet values are based on fuel use data from EIA Form 923 and assumed Hg content of coals as shown in Table 5 and Table 6 in this preamble.

be acceptable in previous rulemakings for Hg controls.[82]

In addition to cost effectiveness, the EPA finds that the revised Hg emission standard for lignite-fired units appropriately considers the costs of controls, both total costs and as a fraction of total revenues, along with other factors that the EPA analyzed pursuant to its CAA section 112(d)(6) authority. Similar to the revised fPM emission standard (as a surrogate for non-Hg HAP metals) discussed in section IV. of this preamble, the EPA anticipates that the total costs of controls (which consists of small annual incremental operating costs) to comply with the revised Hg emission standard will be a small fraction of the total revenues for the impacted lignite-fired units. The EPA expects that sources will be able to meet the revised emission standard using existing controls (*e.g.,* using existing sorbent injection equipment), and that significant additional capital investment is unlikely. If site-specific conditions necessitate minor capital improvements to the ACI control technology, it is important to note that any incremental capital would be small relative to ongoing sorbent costs accounted for in this analysis. Further, in addition to the EPA finding that costs are reasonable for the revised Hg standard for lignite-fired EGUs, the revised standard will also bring these higher emitting sources of Hg emission in line with Hg emission rates that are achieved by non-lignite-fired EGUs. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

Despite the known differences in the quality and composition of the various coal types, the EPA can find no compelling reasons why EGUs that are firing lignite cannot meet the same emission limit as EGUs that are firing other types of coal (*e.g.,* eastern and western bituminous coal, subbituminous coal, and anthracitic and bituminous waste coal). Each of the coal types/ranks has unique compositions and properties. Low halogen content in coal is known to make Hg capture more challenging. But, both lignites and subbituminous coals have low halogen content with higher alkaline content. Lignites tend to have average higher Hg content than subbituminous and bituminous coals—especially lignites mined in Mississippi and Texas. However, waste coals (anthracitic and bituminous coal refuse) tend to have the highest average Hg content. Lignites tend to have higher sulfur content than that of subbituminous coals and the sulfur in the coal can form SO_3 in the flue gas. This SO_3 is known to make Hg capture using sorbent injection more challenging. However, bituminous coals and waste coals have similar or higher levels of sulfur. The formation of SO_3 is more significant with these coals. Despite all the obstacles and challenges presented to EGUs firing non-lignite coals, all of those EGUs have been subject to the more stringent Hg emission limit of 1.2 lb/TBtu—and emit at or below that emission limit since the rule was fully implemented. Advanced, better performing Hg controls—including ''SO_3 tolerant'' sorbents—are available to allow lignite-fired EGUs to also emit at or below the more stringent Hg emission limit of 1.2 lb/TBtu. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

VI. What is the rationale for our other final decisions and amendments from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the other NESHAP requirements?

The EPA did not propose any changes to the organic HAP work practice standards, acid gas standards, continental liquid oil-fired EGU standards, non-continental liquid oil-fired EGUs, limited-use oil-fired EGU standards, or standards for IGCC EGUs. The EPA proposed to require that IGCC EGUs use PM CEMS for compliance demonstration with their fPM standard.

The EPA did note in the 2023 Proposal that there have been several recent temporary and localized increases in oil combustion at continental liquid oil-fired EGUs during periods of extreme weather conditions, such as the 2023 polar vortex in New England. As such, the EPA solicited comment on whether the current definition of the limited-use liquid oil-fired subcategory remains appropriate or if, given the increased reliance on oil-fired generation during periods of extreme weather, a period other than the current 24-month period or a different threshold would be more appropriate for the current definition. The EPA also solicited comment on the appropriateness of including new HAP standards for EGUs subject to the limited use liquid oil-fired subcategory, as well as on the means of demonstrating compliance with the new HAP standards.

B. How did the technology review change for the other NESHAP requirements?

The technology review for the organic HAP work practice standards, acid gas standards, and standards for oil-fired EGUs has not changed from the proposal.

The proposed technology review with respect to the use of PM CEMS for compliance demonstration by IGCC EGUs has changed due to comments received on the very low fPM emission rates and on technical challenges with certifying PM CEMS on IGCC EGUs. Therefore, the Agency is not finalizing the required use of PM CEMS for compliance demonstration with the fPM emission standard at IGCC EGUs.

C. What key comments did we receive on the other NESHAP requirements, and what are our responses?

Comment: Commenters urged the EPA to retain the current definition of the limited-use liquid oil-fired subcategory and not to impose new HAP standards on EGUs in this subcategory, given that there are already limits on the amount of fuel oil that can be burned. Commenters noted that the Agency has not identified any justification for the costs required for implementation and compliance with new HAP standards for limited-use liquid oil-fired EGUs. Some commenters alleged that any changes to the existing HAP standards for EGUs in the limited-use liquid oil-fired subcategory may complicate reliability management during cold winter spells or other extreme weather events.

Response: The Agency did not propose changes to the limited-use liquid oil-fired EGU subcategory or to the requirements for such units. To evaluate the potential HAP emission impact of liquid oil-fired EGUs[83] during extreme weather events, the Agency reviewed the 2022 fPM emissions of 11 liquid oil-fired EGUs in the Northeast U.S. that were operated during December 2022 Winter Storm Elliot, as described in the 2024 Technical Memo. The review found that total non-Hg HAP metal emissions during 2022 from the 11 oil-fired EGUs in New England were very small—approximately 70 times lower than the non-Hg HAP metal emissions estimated from oil-fired units

[82] For example, the EPA proposed that $27,500 per lb of Hg removed was cost-effective for the Primary Copper RTR (87 FR 1616); and approximately $27,000 per lb of Hg ($2021) was found to be cost-effective in the beyond-the-floor analysis supporting the 2012 MATS Final Rule.

[83] Oil-fired EGUs burning residual fuel oil have generally higher emission rates of HAP compared to that from the use of other types of fuel.

in Puerto Rico, which were among the facilities with the highest (but acceptable) residual risk in the 2020 Residual Risk Review.[84] The EPA will continue to monitor the emissions from the dispatch of limited-use liquid oil-fired EGUs—especially during extreme weather events.

In addition, the Agency reviewed the performance of PM CEMS for compliance demonstration at oil-fired EGUs. Given the higher emission rates and limits from this subcategory of EGUs, the Agency did not find any of the correlation issues with the use of PM CEMS with oil-fired EGUs similar to those that were discussed earlier for coal-fired EGUs. Moreover, the benefits of PM CEMS use that were described earlier (*i.e.,* emissions transparency, operational feedback, *etc.*) translate well to oil-fired EGUs; therefore, the EPA is finalizing the requirement for oil-fired EGUs (excluding limited-use liquid oil-fired EGUs) to use PM CEMS for compliance demonstration, as proposed.

Comment: One commenter recommended that units involved with carbon capture and sequestration (CCS) projects retain the option to use stack testing for compliance demonstration. They said that PM emissions would be measured from the stack downstream of the carbon capture system (they specifically mentioned the carbon capture system being contemplated to be built to capture CO_2 emission from the Milton R. Young Station facility in North Dakota). The commenters said that PM CEMS correlation testing will cause operational impacts on the CCS operations due to operational changes or reduced control efficiencies that temporarily increase PM emissions for long time periods, resulting in CCS operations being adversely affected or even shut down for long periods.

Response: The Agency disagrees with the commenter's recommendation that units utilizing a carbon capture system should be able to continue to use periodic stack testing for compliance demonstration. At the present time, the many ways that CCS can be employed and deployed at coal-fired EGUs supports the use of PM CEMS for compliance purposes. For example, measures (such as a bypass stack) are available that would minimize the operational impacts on the carbon capture system and would allow for proper PM CEMS correlations. Furthermore, the Agency finds that the increased transparency and the improved ability to detect and correct potential control or operational problems offered by PM CEMS, as well as the greater assurance of continuous compliance, outweigh the minor operational impacts potentially experienced. To the extent that a specific coal- or oil-fired EGU utilizing CCS wishes to use an alternative test method for compliance demonstration purposes, its owner or operator may submit a request to the Administrator under the provisions of 40 CFR 63.7(f).

D. What is the rationale for our final approach and decisions regarding the other NESHAP requirements?

The Agency did not receive comments that led to any changes in the outcome of the technology review for other NESHAP requirements as presented in the 2023 Proposal. The Agency did not propose any changes for the current requirements for organic HAP work practice standards, acid gas standards, or standards for oil-fired EGUs and therefore no changes are being finalized.

The EPA is aware of two existing IGCC facilities that meet the definition of an IGCC EGU. The Edwardsport Power Station, located in Knox County, Indiana, includes two IGCC EGUs that had 2021 average capacity factors of approximately 85 percent and 67 percent. These EGUs have LEE qualification for PM, with most current test results of 0.0007 and 0.0003 lb/MMBtu, respectively. The Polk Power Station, located in Polk County, Florida, had a 2021 average capacity factor of approximately 70 percent but burned only natural gas in 2021 (*i.e.,* operating essentially as a natural gas combined cycle turbine EGU). Before this EGU switched to pipeline quality natural gas as a fuel, it qualified for PM LEE status in 2018; to the extent that the EGU again operates as an IGCC, it could continue to claim PM LEE status. While this subcategory has a less stringent fPM standard of 0.040 lb/MMBtu (as compared to that of coal-fired EGUs), recent compliance data indicate fPM emissions well below the most stringent standard option of 0.006 lb/MMBtu that was evaluated for coal-fired EGUs.

The EPA is not finalizing the required use of PM CEMS for compliance demonstration for IGCC EGUs due to technical limitations expressed by commenters. For example, commenters noted that due to differences in stack design, the only possible installation space for a PM CEMS on an IGCC facility is on a stack with elevated grating, exposing the instrument to the elements, which would impact the sensitivity and accuracy of a PM CEMS. Additionally, there are no PM control devices at an IGCC unit available for de-tuning, which is necessary for establishing a correlation curve under PS–11. The EPA has considered these comments and agrees with these noted challenges to the use of PM CEMS at IGCC EGUs and, for those reasons, the EPA is not finalizing the proposed requirement for IGCCs to use PM CEMS for compliance demonstration, thus IGCCs will continue to demonstrate compliance via fPM emissions testing. As a result of comments we received on coal-fired run durations and our consideration on those comments, along with the low levels of reported emissions, the EPA determined that owners or operators of IGCCs will need to ensure each run has a minimum sample volume of 2 dscm or a minimum mass collection of 3 milligrams. In addition, IGCC EGUs will continue to be able to obtain and maintain PM LEE status.

VII. Startup Definition for the Coal- and Oil-Fired EGU Source Category

A. What did we propose for the Coal- and Oil-Fired EGU source category?

In the 2023 Proposal, the EPA proposed to remove the alternative work practice standards, *i.e.,* those contained in paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 from the rule based on a petition for reconsideration from environmental groups that was remanded to the EPA in *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020), and responding in part to a separate petition for reconsideration from environmental groups, that sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review.[85] The first option under paragraph (1) defines startup as either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose, including onsite use. In the second option, startup is defined as the period in which operation of an EGU is initiated for any purpose, and startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown

[84] See *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2019 Risk and Technology Review Proposed Rule* (Docket ID No. EPA–HQ–OAR–2018–0794–0014).

[85] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov.*

event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any purpose (including onsite use), or 4 hours after the EGU makes useful thermal energy for industrial, commercial, heating, or cooling purposes, whichever is earlier.

As described in the 2023 Proposal, the Agency proposed to remove paragraph (2) of the definition of ''startup'' as part of our obligation to address the remand on this issue. In addition, as the majority of EGUs currently rely on work practice standards under paragraph (1) of the definition of ''startup,'' we believe this change is achievable by all EGUs and would result in little to no additional expenditures, especially since the additional reporting and recordkeeping requirements associated with use of paragraph (2) would no longer apply. Lastly, the time period for engaging PM or non-Hg HAP metal controls after non-clean fuel use, as well as for full operation of PM or non-Hg HAP metal controls, is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

B. How did the startup provisions change for the Coal- and Oil-Fired EGU source category?

The EPA is finalizing the amendment to remove paragraph (2) from the definition of ''startup'' as proposed.

C. What key comments did we receive on the startup provisions, and what are our responses?

We received both supportive and adverse comments on the proposed removal of paragraph (2) of the definition of ''startup.'' The summarized comments and the EPA's responses are provided in the *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments* document. The most significant adverse comments and the EPA's responses are provided below.

Comment: Commenters recommended that the 4-hour startup definition should continue to be allowed as removing it for simplicity is not an adequate justification. They said the EPA is conflating the MACT standard-setting process with this RTR process. Although the EPA notes that the best performing 12 percent of sources do not need this alternative startup definition, commenters stated that this change is beyond the scope of the technology review. Commenters asserted that the EPA's determination that only eight EGUs are currently using that option is insufficient justification for eliminating the definition. Given that the 2023 Proposal did not identify any flaws with the current definition, the commenters stated that the EPA should explain why elimination of the 4-hour definition from MATS is appropriate when there are units currently relying on it. Commenters also stated that the EPA should consider providing reasonable exemptions for the EGUs that currently use that definition, thus gradually phasing out the definition without imposing any additional compliance burdens. The commenters also argued that with potentially lower fPM standards, more facilities may need the additional flexibility allowed by this definition of startup as their margin of compliance is reduced. They noted that startup or non-steady state operation is not conducive to CEMS accuracy and that it may create false reporting of emissions data biased either high or low depending on the actual conditions.

Commenters stated that several facilities are currently required to use the 4-hour startup definition per federal consent decrees or state agreements. They said such a scenario provides clear justification for a limited exemption, as MATS compliance should not result in an EGU violating its consent decree. Commenters noted other scenarios where state permits have special conditions with exemptions from emission limits during ramp-up or ramp-down periods. They said many facilities alleviate high initial emissions by using alternate fuels to begin the combustion process, which has been demonstrated as a Best Management Practice and to lower emissions. Commenters noted that the permit modification process, let alone any physical or operational modifications to the facility, could take significantly longer than the 180-day compliance deadline, depending on public comments, meetings, or contested hearing requests made during the permit process.

Commenters stated the startup definition paragraph (2) has seen limited use due to the additional reporting requirements that the EPA imposed on sources that chose to use the definition, which they believe are unnecessary and should be removed from the rule. The commenters said that the analysis the EPA conducted during the startup/shutdown reconsideration in response to *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020) showed that the definition was reasonable, and they argued that the definition may be needed if the EPA further reduces the limits, given the transitory nature of unit and control operation during these periods. Commenters also stated that the startup definition paragraph (2) is beneficial to units that require extended startups. They said including allowances for cold startup conditions could allow some EGUs to continue operation until more compliant generation is built, which would help facilitate a smooth transition to newer plants that meet the requirements without risking the reliability of the electric grid. Commenters also noted that some control devices, such as ESPs, may not be operating fully even when the plant begins producing electricity.

Commenters stated that the EPA should consider allowing the use of diluent cap values from 40 CFR part 75. As these are limited under MATS, commenters noted that startup and shutdown variations are more pronounced than if diluent caps were to be allowed. They said that with a lower emissions limitation, the diluent cap would mathematically correct for calculation inaccuracies inherent in emission rate calculation immediately following startup. Commenters stated that relative accuracy test audits (RATA) must be conducted at greater than 50 percent load under 40 CFR part 60 and at normal operating load under 40 CFR part 75. They said that it is not reasonable to require facilities to certify their CEMS, including PM CEMS, at greater than 50 percent capacity and use it for compliance at less than 50 percent capacity. Commenters stated that startups have constantly changing flow and temperatures that do not allow compliance tests to be conducted during these periods.

Response: The Agency disagrees with the commenters who suggest that the 4-hour startup duration should be retained. As mentioned in the 2023 Proposal (88 FR 24885), owners or operators of coal- and oil-fired EGUs that generated over 98 percent of electricity in 2022 have made the requisite adjustments, whether through greater clean fuel capacity, better tuned equipment, better trained staff, a more efficient and/or better design structure, or a combination of factors, to be able to meet the requirements of paragraph (1) of the startup definition. This ability points out an improvement in operation that all EGUs should be able to meet at little to no additional expenditure, since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the startup definition were more expensive than the requirements of paragraph (1) of the definition. As mentioned with respect to gathering experience with PM CEMS, the Agency believes owners or operators of the 8 EGUs relying on the 4-hour startup period can build on their startup experience gained since finalization of the 2012 MATS Final Rule, along with the experience shared by some of the other EGUs that have been able to conform with startup definition paragraph (1), as well as the experience to be obtained in the period yet remaining before compliance is required; such experience could prove key to aiding source owners or operators in their shift from reliance on startup definition paragraph (2) to startup definition paragraph (1). Should EGU owners or operators find that their attempts to rely on startup definition (1) are unsuccessful after application of that experience, they may request of the Administrator the ability to use an alternate non-opacity standard, as described in the NESHAP general provisions at 40 CFR 63.6(g). Before the Administrator's approval can be granted, the EGU owner or operator's request must appear in the **Federal Register** for the opportunity for notice and comment by the public, as required in 40 CFR 63.6(g)(1).

Regarding consent decrees or state agreements for requirements other than those contained in this rule, while the rule lacks the ability to revise such agreements, the EPA recommends that EGU owners or operators contact the other parties to see what, if any, revisions could be made. Nonetheless, the Agency expects EGU source owners or operators to comply with the revised startup definition by the date specified in this rule. Given the concern expressed by the commenters for some sources, the Agency expects such source owners or operators to begin negotiations with other parties for other non-rule obligations to begin early enough to be completed prior to the compliance date specified in this rule.

The Agency disagrees with the commenters' suggestions that startup definition paragraph (2)'s reporting requirements were too strict to be used. That suggestion is not consistent with the number of commenters who claimed to need to use paragraph (2) of the startup definition, even though only 2.5 percent of EGUs currently rely on this startup definition. The Agency's experience is that almost all EGU source owners or operators have been able to adjust their unit operation such that adherence to startup definition paragraph (1) reduced, if not eliminated, the concern by some about use of startup definition paragraph (1). As mentioned earlier in this document, the better performers in the coal-fired EGU source category no longer need to have, or use, paragraph (2) of the startup definition after gaining experience with using paragraph (1).

The Agency disagrees with the commenter's suggestion that the diluent cap values allowed for use by 40 CFR part 75 be included in the rule, because diluent cap values are already allowed for use during startup and shutdown periods per 40 CFR 63.10007(f)(1). Note that while emission values are to be recorded and reported during startup and shutdown periods, they are not to be used in compliance calculations per 40 CFR 63.10020(e). In addition to diluent cap use during startup and shutdown periods, section 6.2.2.3 of appendix C to 40 CFR part 63, subpart UUUUU allows diluent cap use for PM CEMS during any periods when oxygen or CO_2 values exceed or dip below, respectively, the cap levels. Diluent cap use for other periods from other regulations are not necessary for MATS. The Agency does not understand the commenter's suggestion concerning the load requirement for a RATA. The Agency believes the commenter may have mistaken HCl CEMS requirements, which use RATAs but were not proposed to be changed, with PM CEMS requirements, which do not use RATAs. Since PM CEMS are not subject to RATAs and the Agency did not propose changes to requirements for HCl CEMS, the comment on RATAs being conducted at greater than 50 percent load is moot. The EPA is finalizing the removal of startup definition paragraph (2), as proposed.

D. What is the rationale for our final approach and final decisions for the startup provisions?

The EPA is finalizing the removal of paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 consistent with reasons described in the 2023 Proposal. As the majority of EGUs are already relying on the work practice standards in paragraph (1) of the startup definition, the EPA finds that such a change is achievable within the 180-day compliance timeline by all EGUs at little to no additional expenditure since the additional reporting and recordkeeping provisions under paragraph (2) were more expensive than paragraph (1). Additionally, the time period for engaging pollution controls for PM or non-Hg HAP metals is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

VIII. What other key comments did we receive on the proposal?

Comment: Some commenters argued that it is well-established that cost is a major consideration in rulemakings reviewing existing NESHAP under CAA section 112(d)(6). In particular, commenters cited to *Michigan* v. *EPA,* 576 U.S. 743, 759 (2015), to support the argument that the EPA must consider the costs of the regulation in relation to the benefits intended by the statutory requirement mandating this regulation, that is, the benefits of the HAP reductions. Commenters stated that the EPA should not seek to impose the excessive costs associated with this action as there would be no benefit associated with reducing HAP. The commenters said that the EPA certainly should not do so for an industry that is rapidly reducing its emissions because it is on the way to retiring most, if not all, units in the source category in little over a decade. The commenters also claimed that as *Michigan* held that cost and benefits must be considered in determining whether it is ''appropriate'' to regulate EGUs under CAA section 112 in the first place, it necessarily follows that the same threshold must also apply when the EPA subsequently reviews the standards.

Response: The EPA agrees that it is appropriate to take costs into consideration in deciding whether it is necessary to revise an existing NESHAP under CAA section 112(d)(6). As explained in the 2023 Proposal and this document, the EPA has carefully considered the costs of compliance and the effects of those costs on the industry. Although the commenters seem to suggest that the EPA should weigh the costs and benefits of the revisions to the standard, we do not interpret the comments as arguing that the EPA should undertake a formal benefit cost analysis but rather the commenters believe that the EPA should instead limit its analysis supporting the standard to HAP emission reductions. Our consideration of costs in this rulemaking is consistent with the Supreme Court's direction in *Michigan* where the Court noted that ''[i]t will be up to the Agency to decide (as always, within the limits of reasonable interpretation) how to account for cost,'' 576 U.S. 743, 759 (2015), and with comments arguing that the EPA should focus its decision-making on the standard on the anticipated reductions in HAP.

In *Michigan,* the Supreme Court concluded that the EPA erred when it concluded it could not consider costs when deciding as a threshold matter whether it is ''appropriate and necessary'' under CAA section 112(n)(1)(A) to regulate HAP from EGUs, despite the relevant statutory provision containing no specific reference to cost. 576 U.S. at 751. In doing so, the Court held that the EPA ''must consider cost—including, most importantly, cost of compliance—before deciding whether regulation is appropriate and necessary'' under CAA section 112. *Id.* at 759. In examining the language of CAA section 112(n)(1)(A), the Court concluded that the phrase ''appropriate and necessary'' was ''capacious'' and held that ''[r]ead naturally in the present context, the phrase 'appropriate and necessary' requires at least some attention to cost.'' *Id.* at 752. As is clear from the record for this rulemaking, the EPA has carefully considered cost in reaching its decision to revise the NESHAP in this action.

The EPA has also taken into account the numerous HAP-related benefits of the final rule in deciding to take this action. These benefits include not only the reduced exposure to Hg and non-Hg HAP metals, but also the additional transparency provided by PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS will provide that the standards are being met on a continuous basis. As discussed in section II.B.2., and section IX.E. many of these important benefits are not able to be monetized. Although this rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium, data limitations prevent the EPA from assigning monetary value to those reductions. In addition, there are several benefits associated with the use of PM CEMS which are not quantified in this rule.

While the Court's examination of CAA section 112(n)(a)(1) in *Michigan* considered a different statutory provision than CAA section 112(d)(6) under which the EPA is promulgating this rulemaking, the EPA has nonetheless satisfied the Court's directive to consider costs, both in the context of the individual revisions to MATS (as directed by the language of the statute) and in the context of the rulemaking as a whole. Moreover, while the EPA is not required to undertake a ''formal cost benefit analysis in which each advantage and disadvantage [of a regulation] is assigned a monetary value,'' *Michigan,* 576 U.S. at 759, the EPA has contemplated and carefully considered both the advantages and disadvantages of the revisions it is finalizing here, including qualitative and quantitative benefits of the regulation and the costs of compliance.

IX. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

The following analyses of costs and benefits, and environmental, economic, and environmental justice impacts are presented for the purpose of providing the public with an understanding of the potential consequences of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discussed in section II.A. and sections IV. through VII.

The EPA's obligation to conduct an analysis of the potential costs and benefits under Executive Order 12866, discussed in this section and section X.A., is distinct from its obligation in setting standards under CAA section 112 to take costs into account. As explained above, the EPA considered costs in multiple ways in choosing appropriate standards consistent with the requirements of CAA section 112. The benefit-cost analysis is performed to comply with Executive Order 12866. The EPA, however, did not rely on that analysis in choosing the appropriate standard here, consistent with the Agency's longstanding interpretation of the statute. As discussed at length in section II.B.2. above and in the EPA's 2023 final rulemaking finalizing the appropriate and necessary finding (88 FR 13956), historically there have been significant challenges in monetizing the benefits of HAP reduction. Important categories of benefits from reducing HAP cannot be monetized, making benefit-cost analysis ill-suited to the EPA's decision making on regulating HAP emissions under CAA section 112. Further, there are also unquantified emission reductions anticipated from installing PM CEMS, as discussed in section IX.E. For this reason, combined with Congress's recognition of the particular dangers posed by HAP and consequent direction to the EPA to reduce emissions of these pollutants to the ''maximum degree,'' the EPA does not at this time believe it is appropriate to rely on the results of the monetized benefit-cost analysis when setting the standards.

As noted in section X.A. below, the EPA projects that the net monetized benefits of this rule are negative. Many of the benefits of this rule discussed at length in this section and elsewhere in this record, however, were not monetized. This rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium,[86] consistent with Congress's direction in CAA section 112 discussed in section II.A. of this final rule. At this time, data limitations prevent the EPA from assigning monetary value to those reductions, as discussed in section II.B.2. above.[87] In addition, the benefits of the additional transparency provided by the requirement to use PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS provide that the standards are being met on a continuous basis were not monetized due to data limitations. While the EPA does not believe benefit-cost analysis is the right way to determine the appropriateness of a standard under CAA section 112, the EPA notes that when all of the costs and benefits are considered (including non-monetized benefits), this final rule is a worthwhile exercise of the EPA's CAA section 112(d)(6) authority.

A. What are the affected facilities?

The EPA estimates that there are 314 coal-fired EGUs [88] and 58 oil-fired EGUs that will be subject to this final rule by the compliance date.

B. What are the air quality impacts?

The EPA estimated emission reductions under the final rule for the years 2028, 2030, and 2035 based upon IPM projections. The quantified emissions estimates were developed with the EPA's Power Sector Modeling Platform 2023 using IPM, a state-of-the-art, peer-reviewed dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. IPM provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies while meeting electricity demand and various environmental, transmission, dispatch, and reliability constraints. IPM's least-cost dispatch

[86] As of 2023, three of the HAP metals or their compounds emitted by EGUs (arsenic, chromium, and nickel) are classified as carcinogenic to humans. More details are available in section II.B.2. and Chapter 4.2.2 of the RIA.

[87] *See also National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023) (for additional discussion regarding the limitations to monetizing and quantifying most benefits from HAP reductions in the 2023 rulemaking finalizing the appropriate and necessary finding).

[88] The number of coal-fired affected EGUs is larger than the 296 coal-fired EGUs assessed for the fPM standard in section IV. because it includes four EGUs that burn petroleum coke (which are a separate subcategory for MATS) and 14 EGUs without fPM compliance data available on the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), *https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

solution is designed to ensure generation resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system. The model includes state-of-the-art estimates of the cost and performance of air pollution control technologies with respect to Hg and other HAP controls.

The quantified emission reduction estimates presented in the RIA include reductions in pollutants directly covered by this rule, such as Hg, and changes in other pollutants emitted from the power sector as a result of the compliance actions projected under this final rule. Table 8 of this document presents the projected emissions under the final rule. Note that, unlike the cost-effectiveness analysis presented in sections IV. and V. of this preamble, the projections presented in table 8 are incremental to a projected baseline which reflects future changes in the composition of the operational coal-fired EGU fleet that are projected to occur by 2035 as a result of factors affecting the power sector, such as the IRA, promulgated regulatory actions, or changes in economic conditions.

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Table 8. Projected EGU Emissions in the Baseline and Under the Final Rule: 2028, 2030, and 2035[a]

		Total Emissions			
	Year	Baseline	Final Rule	Change from Baseline	% Change
Hg (lb)	2028	6,129	5,129	-999	-16%
	2030	5,863	4,850	-1,013	-17%
	2035	4,962	4,055	-907	-18%
$PM_{2.5}$ (thousand tons)	2028	70.5	69.7	-0.8	-1.1%
	2030	66.3	65.8	-0.5	-0.8%
	2035	50.7	50.2	-0.5	-0.9%
PM_{10} (thousand tons)	2028	79.5	77.4	-2.1	-2.6%
	2030	74.5	73.1	-1.3	-1.8%
	2035	56.0	54.8	-1.2	-2.1%
SO_2 (thousand tons)	2028	454.3	454.0	-0.3	-0.1%
	2030	333.5	333.5	0.0	0.0%
	2035	239.9	239.9	0.0	0.0%
Ozone-season NO_x (thousand tons)	2028	189.0	188.8	-0.165	-0.09%
	2030	174.9	175.4	0.488	0.28%
	2035	116.9	119.1	2.282	1.95%
Annual NO_x (thousand tons)	2028	460.5	460.3	-0.283	-0.06%
	2030	392.8	392.7	-0.022	-0.01%
	2035	253.4	253.5	0.066	0.03%
HCl (thousand tons)	2028	2.5	2.5	0.0	0.0%
	2030	2.2	2.2	0.0	0.0%
	2035	1.5	1.5	0.0	0.1%
CO_2 (million metric tons)	2028	1,158.8	1,158.7	-0.1	0.0%
	2030	1,098.3	1,098.3	0.0	0.0%
	2035	724.2	724.1	-0.1	0.0%

[a] This analysis is limited to the geographically contiguous lower 48 states.

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In addition to the projected emissions impacts presented in table 8, we also estimate that the final rule will reduce at least 7 tons of non-Hg HAP metals in 2028, 5 tons of non-Hg HAP metals in 2030, and 4 tons of non-Hg HAP metals in 2035. These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.[89]

Importantly, the continuous monitoring of fPM required in this rule will likely induce additional emissions reductions that we are unable to quantify. Continuous measurements of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that fPM emissions could be lower than they otherwise would have been for up to 3 months—or up to 3 years if testing less frequently under the LEE program—at a time. This potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the existing coal-fired fleet and is not quantified in this rulemaking.

Section 3 of the RIA presents a detailed discussion of the emissions projections under the regulatory options as described in the RIA. Section 3 also describes the compliance actions that are projected to produce the emission reductions in table 8 of this preamble. Please see section IX.E. of this preamble and section 4 of the RIA for detailed discussions of the projected health, welfare, and climate benefits of these emission reductions.

C. What are the cost impacts?

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In other words, these costs are an estimate of the increased power industry expenditures required to implement the final requirements of this rule. The compliance cost estimates were mainly developed using the EPA's Power Sector Modeling Platform 2023 using IPM. The incremental costs of the final rule's PM CEMS requirement were estimated outside of IPM and added to the IPM-based cost estimate presented here and in section 3 of the RIA.

We estimate the present value (PV) of the projected compliance costs over the 2028 to 2037 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. All dollars are in 2019 dollars. We estimate the PV and EAV using 2, 3, and 7 percent discount rates.[90] Table 9 of this document presents the estimates of compliance costs for the final rule.

Table 9. Projected Compliance Costs of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	2% Discount Rate	3% Discount Rate	7% Discount Rate
PV	860	790	560
EAV	96	92	80

[a] Values have been rounded to two significant figures.

The PV of the compliance costs for the final rule, discounted at the 2 percent rate, is estimated to be about $860 million, with an EAV of about $96 million. At the 3 percent discount rate, the PV of the compliance costs of the final rule is estimated to be about $790 million, with an EAV of about $92 million. At the 7 percent discount rate, the PV of the compliance costs of the rule is estimated to be about $560 million, with an EAV of about $80 million.

We note that IPM provides the EPA's best estimate of the costs of the rules to the electricity sector and related energy sectors (*i.e.,* natural gas, coal mining). These compliance cost estimates are used as a proxy for the social cost of the rule. For a detailed description of these compliance cost projections, please see section 3 of the RIA, which is available in the docket for this action.

D. What are the economic impacts?

The Agency estimates that this rule will require additional fPM and/or Hg removal at less than 15 GW of operable capacity in 2028, which is about 14 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM and/or Hg removal are projected to generate less than 2 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule.

Consistent with the small share of EGUs required to reduce fPM and/or Hg emissions rates, this final action has limited energy market implications. There are limited impacts on energy prices projected to result from this final rule. On a national average basis,

[89] Note that modeled projections include total PM_{10} and total $PM_{2.5}$. The EPA estimated non-Hg HAP metals reductions by multiplying the ratio of non-Hg HAP metals to fPM by modeled projections of total PM_{10} reductions under the rule. The ratios of non-Hg HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-Hg HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-Hg HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category.*

[90] Results using the 2 percent discount rate were not included in the proposal for this action. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

delivered coal, natural gas, and retail electricity prices are not projected to change. The EPA does not project incremental changes in existing operational capacity to occur in response to the final rule. Coal production for use in the power sector is not projected to change significantly by 2028.

The short-term estimates for employment needed to design, construct, and install the control equipment in the 3-year period before the compliance date are also provided using an approach that estimates employment impacts for the environmental protection sector based on projected changes from IPM on the number and scale of pollution controls and labor intensities in relevant sectors. Finally, some of the other types of employment impacts that will be ongoing are estimated using IPM outputs and labor intensities, as reported in section 5 of the RIA.

E. What are the benefits?

The RIA for this action analyzes the benefits associated with the projected emission reductions under this rule. This final rule is projected to reduce emissions of Hg and non-Hg HAP metals, as well as $PM_{2.5}$, SO_2, NO_X and CO_2 nationwide. The potential impacts of these emission reductions are discussed in detail in section 4 of the RIA. The EPA notes that the benefits analysis is distinct from the statutory determinations finalized herein, which are based on the statutory factors the EPA is required to consider under CAA section 112. The assessment of benefits described here and in the RIA is presented solely for the purposes of complying with Executive Order 12866, as amended by Executive Order 14094, and providing the public with a complete depiction of the impacts of the rulemaking.

Hg is a persistent, bioaccumulative toxic metal emitted from power plants that exists in three forms: gaseous elemental Hg, inorganic Hg compounds, and organic Hg compounds (*e.g.,* methylmercury). Hg can also be emitted in a particle-bound form. Elemental Hg can exist as a shiny silver liquid, but readily vaporizes into air. Airborne elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and particle-bound Hg deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, methylmercury is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have methylmercury concentrations many times that of the concentrations in the freshwater body in which they live.

All forms of Hg are toxic, and each form exhibits different health effects. Acute (short-term) exposure to high levels of elemental Hg vapors results in central nervous system (CNS) effects such as tremors, mood changes, and slowed sensory and motor nerve function. Chronic (long-term) exposure to elemental Hg in humans also affects the CNS, with effects such as erethism (increased excitability), irritability, excessive shyness, and tremors. The major effect from chronic ingestion or inhalation of low levels of inorganic Hg is kidney damage.

Methylmercury is the most common organic Hg compound in the environment. Acute exposure of humans to very high levels of methylmercury results in profound CNS effects such as blindness and spastic quadriparesis. Chronic exposure to methylmercury, most commonly by consumption of fish from Hg contaminated waters, also affects the CNS with symptoms such as paresthesia (a sensation of pricking on the skin), blurred vision, malaise, speech difficulties, and constriction of the visual field. Ingestion of methylmercury can lead to significant developmental effects, such as IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability. In addition, evidence in humans and animals suggests that methylmercury can have adverse effects on both the developing and the adult cardiovascular system, including fatal and non-fatal ischemic heart disease (IHD). Further, nephrotoxicity, immunotoxicity, reproductive effects (impaired fertility), and developmental effects have been observed with methylmercury exposure in animal studies.[91] Methylmercury has some genotoxic activity and can cause chromosomal damage in several experimental systems. The EPA has concluded that mercuric chloride and methylmercury are possibly carcinogenic to humans.[92 93]

The projected emissions reductions of Hg are expected to lower deposition of Hg into ecosystems and reduce U.S. EGU attributable bioaccumulation of methylmercury in wildlife, particularly for areas closer to the effected units subject to near-field deposition. Subsistence fishing is associated with vulnerable populations. Methylmercury exposure to subsistence fishers from lignite-fired units is below the current RfD for methylmercury neurodevelopmental toxicity. The EPA considers exposures at or below the RfD for methylmercury unlikely to be associated with appreciable risk of deleterious effects across the population. However, the RfD for methylmercury does not represent an exposure level corresponding to zero risk; moreover, the RfD does not represent a bright line above which individuals are at risk of adverse effects. Reductions in Hg emissions from lignite-fired facilities should further reduce exposure to methylmercury for subsistence fisher sub-populations located in the vicinity of these facilities, which are all located in North Dakota, Texas, and Mississippi.

In addition, U.S. EGUs are a major source of HAP metals emissions including selenium, arsenic, chromium, nickel, and cobalt, cadmium, beryllium, lead, and manganese. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. The emissions reductions projected under this final rule are expected to reduce human exposure to non-Hg HAP metals, including carcinogens.

Furthermore, there is the potential for reductions in Hg and non-Hg HAP metal emissions to enhance ecosystem services and improve ecological outcomes. The reductions will potentially lead to positive economic impacts although it is difficult to estimate these benefits and, consequently, they have not been included in the set of quantified benefits.

As explained in section IX.B., the continuous monitoring of fPM required in this rule may induce further reductions of fPM and non-Hg HAP metals than we project in the RIA for

[91] Agency for Toxic Substances and Disease Registry (ATSDR). Toxicological Profile for Mercury. Public Health Service, U.S. Department of Health and Human Services, Atlanta, GA. 2022.

[92] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 2001.

[93] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Mercuric Chloride. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1995.

this action. As a result, there may be additional unquantified beneficial health impacts from these potential reductions. The continuous monitoring of fPM required in this rule is also likely to provide several additional benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today.

The rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. The rule is also expected to reduce ozone-season NO_X emissions nationally in most years of analysis. In the presence of sunlight, NO_X, and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and reduces the incidence of ozone-related health effects, although the degree to which ozone is reduced will depend in part on local concentration levels of VOCs.

The health effect endpoints, effect estimates, benefit unit values, and how they were selected, are described in the technical support document titled *Estimating $PM_{2.5}$* minus; *and Ozone-Attributable Health Benefits* (2023). This document describes our peer-reviewed approach for selecting and quantifying adverse effects attributable to air pollution, the demographic and health data used to perform these calculations, and our methodology for valuing these effects.

Because of projected changes in dispatch under the final requirements, the rule is also projected to impact CO_2 emissions. The EPA estimates the climate benefits of CO_2 emission reductions expected from the final rule using estimates of the social cost of carbon (SC–CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[94] The EPA published and used these estimates in the RIA for the December 2023 Natural Gas Sector final rule titled *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (2023 Oil and Natural Gas NSPS/EG).[95] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Natural Gas Sector supplemental proposal [96] that preceded the 2023 Oil and Natural Gas NSPS/EG and has conducted an external peer review of these estimates. The response to public comments document and the response to peer reviewer recommendations can be found in the docket for the 2023 Oil and Natural Gas NSPS/EG action. Complete information about the peer review process is also available on the EPA's website.[97]

Section 4.4 within the RIA for this final rulemaking provides an overview of the methodological updates incorporated into the SC–CO_2 estimates used in this final RIA.[98] A more detailed explanation of each input and the modeling process is provided in the final technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.[99]

The SC–CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CO_2 includes the value of all climate change impacts both negative and positive, including, but not limited to, changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CO_2, therefore, reflects the societal value of reducing emissions of CO_2 by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations restrain the ability of SC–CO_2 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Table 10 of this document presents the estimated PV and EAV of the projected health and climate benefits across the regulatory options examined in the RIA in 2019 dollars discounted to 2023.

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[94] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[95] *Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* Docket ID No. EPA–HQ–OAR–2021–0317, December 2023.

[96] *Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* 87 FR 74702 (December 6, 2022).

[97] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.*

[98] Note that the RIA for the proposal of this rulemaking used the SC–CO_2 estimates from the Interagency Working Group's (IWG) February 2021 Social Cost of Greenhouse Gases Technical Support Document (TSD) (IWG 2021) to estimate climate benefits. These SC–CO_2 estimates were interim values recommended for use in benefit-cost analyses until updated estimates of the impacts of climate change could be developed. Estimated climate benefits using these interim SC–CO_2 values (IWG 2021) are presented in Appendix B of the RIA for this final rulemaking for comparison purposes.

[99] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,* Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

Table 10. Projected Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

Present Value (PV)			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Total Monetized Benefits[e]	420	390	300
Equivalent Annual Value (EAV)[b]			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Total Monetized Benefits[e]	47	45	39
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The EAV of benefits are calculated over the 10-year period from 2028 to 2037.

[c] The projected monetized air quality-related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

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This final rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The projected PV of monetized climate benefits of the final rule is estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent.[100] Thus, this final rule would

[100] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under

generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate.

At a 3 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million discounted at 3 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate.

At a 7 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $180 million, with an EAV of about $25 million discounted at 7 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 7 percent rate.

The benefits from reducing Hg and non-Hg HAP metals and from unquantified improvements in water quality were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this rulemaking. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring PM CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find that, if we were able to monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this document.

F. What analysis of environmental justice did we conduct?

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [101]

The environmental justice analysis is presented for the purpose of providing the public with as full as possible an understanding of the potential impacts of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based solely on the statutory factors the EPA is required to consider under that section. To address these questions in the EPA's first quantitative EJ analysis in the context of a MATS rule, the EPA developed a unique analytical approach that considers the purpose and specifics of this rulemaking, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.,* residence of historically red-lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

For this rule, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns in the baseline (question 1).[102] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standards (NAAQS), whereas the $PM_{2.5}$ metric is more similar to the long-term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to this rulemaking and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

In section 6 of the RIA, we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to various local populations with potential EJ concerns (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment,

OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See Section 4.4 of the RIA for more discussion.

[101] See *https://www.epa.gov/environmental justice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[102] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

and degree of linguistic isolation (section 6.5). It is important to note that due to the small magnitude of underlying emissions changes, and the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes, the rule is expected to have only a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other, as each was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in this final rule, traffic, or noise. The baseline analysis indicates that on average the populations living within 10 kilometers of coal plants potentially impacted by the amended fPM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the American Indian population living within 10 kilometers of lignite plants potentially impacted by the amended Hg standard is higher than the national average. Assessing these results, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* SO_2) for various population groups in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure or impact.

As HAP exposure results generated as part of the 2020 Residual Risk Review were below both the presumptive acceptable cancer risk threshold and noncancer health benchmarks and this regulation should further reduce exposure to HAP, there are no ''disproportionate and adverse effects'' of potential EJ concern. Therefore, we did not perform a quantitative EJ assessment of HAP risk. However, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

This rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and because NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of this rulemaking. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanic, Black, below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications. Due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternative under consideration (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy ozone and $PM_{2.5}$ exposure impacts, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[103]

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action,'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is briefly summarized in section IX. of this preamble and here. This analysis is also available in the docket.

Table 11 of this document presents the estimated PV and EAV of the monetizable projected health benefits, climate benefits, compliance costs, and net benefits of the final rule in 2019 dollars discounted to 2023. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rule.

Under Executive Order 12866, the EPA is directed to consider all of the costs and benefits of its actions, not just those that stem from the regulated pollutant. Accordingly, the projected monetized benefits of the final rule include health benefits associated with projected reductions in $PM_{2.5}$ and ozone concentration. The projected monetized benefits also include climate benefits due to reductions in CO_2 emissions. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent. The projected climate

[103] Please note that results for ozone and $PM_{2.5}$ exposures should not be extrapolated to other air pollutants that were not included in the assessment, including HAP. Detailed EJ analytical results can be found in section 6 of the RIA.

benefits in this table are based on estimates of the SC–CO_2 at a 2 percent near-term Ramsey discount rate and are discounted using a 2 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the finalized requirements and represent the EPA's best estimate of the social cost of the final rulemaking.

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Table 11. Projected Monetized Benefits, Compliance Costs, and Net Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	Present Value (PV)		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Compliance Costs	860	790	560
Net Benefits	-440	-400	-260
	Equal Annualized Value (EAV)[b]		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Compliance Costs	96	92	80
Net Benefits	-49	-47	-41
Non-Monetized Benefits[e]	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The EAV of costs and benefits are calculated over the 10-year period from 2028 to 2037.

[c] The projected monetized air quality related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

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As shown in table 11 of this document, this rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The rule is also projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent. Thus, this final rule would generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate. The PV of the projected compliance costs are $860 million, with an EAV of about $96 million discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$440 million and EAV of −$49 million.

At a 3 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate. The PV of the projected compliance costs are $790 million, with an EAV of $92 million discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$400 million and an EAV of −$47 million.

At a 7 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $160 million, with an EAV of about $23 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 3 percent rate. The PV of the projected compliance costs are $560 million, with an EAV of $80 million discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$260 million and an EAV of −$41 million.

The potential benefits from reducing Hg and non-Hg HAP metals and potential improvements in water quality and availability were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this final rule. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find, if we were able to quantify and monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2137–12. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0567.

The information collection activities in this rule include continuous emission monitoring, performance testing, notifications and periodic reports, recording information, monitoring and the maintenance of records. The information generated by these activities will be used by the EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable delegated authorities to identify affected facilities that may not be in compliance with the requirements. Based on reported information, delegated authorities will decide which units and what records or processes should be inspected. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). The burden and cost estimates below represent the total burden and cost for the information collection requirements of the NESHAP for Coal- and Oil-Fired EGUs, not just the burden associated with the amendments in this final rule. The incremental cost associated with these amendments is $2.4 million per year.

Respondents/affected entities: The respondents are owners or operators of coal- and oil-fired EGUs. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU industry are 221112, 221122, and 921150.

Respondent's obligation to respond: Mandatory per 42 U.S.C. 7414 *et seq.*

Estimated number of respondents: 192 per year.[104]

Frequency of response: The frequency of responses varies depending on the burden item. Responses include daily calibrations, monthly recordkeeping activities, semiannual compliance reports, and annual reports.

Total estimated burden: 447,000 hours (per year). Burden is defined at 5 CFR part 1320.3(b).

Total estimated cost: $106,600,000 (per year), includes $53,100,000 in annual labor costs and $53,400,000 annualized capital and operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In the 2028 analysis year, the EPA identified 24 potentially affected small entities operating 45 units at 26 facilities, and of these 24, only one small entity may experience compliance cost increases greater than one percent of revenue under the final rule. Details of this analysis are presented in section 5 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more (adjusted for inflation) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The costs involved in this action are estimated not to exceed $100 million or more (adjusted for inflation) in any one year.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive

[104] Each facility is a respondent and some facilities have multiple EGUs.

Order 13175. The Executive order defines tribal implications as ''actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes.'' The amendments in this action would not have a substantial direct effect on one or more tribes, change the relationship between the Federal Government and tribes, or affect the distribution of power and responsibilities between the Federal Government and Indian tribes. Thus, Executive Order 13175 does not apply to this action.

Although this action does not have tribal implications as specified in Executive Order 13175, the EPA consulted with tribal officials during the development of this action. On September 1, 2022, the EPA sent a letter to all federally recognized Indian tribes initiating consultation to obtain input on this action. The EPA did not receive any requests for consultation from Indian tribes. The EPA also participated in the September 2022 National Tribal Air Association EPA Air Policy Update Call to solicit input on this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866. Accordingly, we have evaluated the potential for environmental health or safety effects from exposure to HAP, ozone, and $PM_{2.5}$ on children. The EPA believes that, even though the 2020 residual risk assessment showed all modeled exposures to HAP to be below thresholds for public health concern, the rule should reduce HAP exposure by reducing emissions of Hg and non-Hg HAP with the potential to reduce HAP exposure to vulnerable populations, including children. The action described in this rule is also expected to lower ozone and $PM_{2.5}$ in many areas, including those areas that struggle to attain or maintain the NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated, including children. The results of this evaluation are contained in the RIA and are available in the docket for this action.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For 2028, the compliance year for the standards, the EPA does not project a significant change in retail electricity prices on average across the contiguous U.S., coal-fired electricity generation, natural gas-fired electricity generation, or utility power sector delivered natural gas prices. Details of the projected energy effects are presented in section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

The following standards appear in the amendatory text of this document and were previously approved for the locations in which they appear: ANSI/ASME PTC 19.10–1981, ASTM D6348–03(R2010), and ASTM D6784–16.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. For this rule, we employ the proximity demographic analysis and the $PM_{2.5}$ and ozone exposure analyses to evaluate disproportionate and adverse human health and environmental effects on communities with EJ concerns that exist prior to the action. The proximity demographic analysis indicates that on average the population living within 10 kilometers of coal plants potentially impacted by the fPM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the American Indian population living within 10 kilometers of lignite-fired plants potentially impacted by the Hg standard is higher than the national average. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanics, Blacks, those below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on communities with environmental justice concerns. Only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the final rule, and whether potential EJ concerns will be created or mitigated. We infer that baseline disparities in ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the final regulatory option due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the baseline disparities. We also do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be exacerbated or mitigated in the final regulatory option, compared to the baseline due to the very small differences in the magnitude of post-policy ozone and $PM_{2.5}$ exposure impacts across demographic populations. Additionally, the potential reduction in Hg and non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

The information supporting this Executive Order review is contained in section IX.F. of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket (EPA–HQ–OAR–2018–0794).

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons set forth in the preamble, 40 CFR part 63 is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. In § 63.14, paragraph (f)(1) is amended by removing the text ''tables 4 and 5 to subpart UUUUU'' and adding, in its place, the text ''table 5 to subpart UUUUU''.

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

■ 3. Section 63.9991 is amended by revising paragraph (a)(2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) * * *

(2) Before July 6, 2027, you must meet each operating limit in Table 4 to this subpart that applies to your EGU.

* * * * *

■ 4. Amend § 63.10000 by:

■ a. Revising paragraph (c)(1)(i) and paragraph (c)(1)(i)(A);

■ b. Redesignating paragraph (c)(1)(i)(C) as paragraph (c)(1)(i)(D);

■ c. Adding new paragraph (c)(1)(i)(C);

■ d. Revising paragraph (c)(1)(iv);

■ e. Adding new paragraphs (c)(1)(iv)(A) through (C);

■ f. Revising paragraphs (c)(2)(i) and (ii);

■ g. Revising paragraph (d)(5)(i); and

■ h. Revising paragraph (m) introductory text.

The revisions and additions read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c) * * *

(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) through (C) of this section:

(A) Except as provided in paragraph (c)(1)(i)(D) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

* * * * *

(C) On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for coal-fired and solid oil-derived fuel-fired EGUs.

* * * * *

(iv)(A) Before July 6, 2027, if your coal-fired or solid oil derived fuel-fired EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(B) On and after July 6, 2027, you may not pursue or continue to use the LEE option for your coal-fired or solid oil derived fuel-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(C) If your IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(2) * * *

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals.

(ii) Before July 6, 2027, if your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly. On and after July 6, 2027, you may not pursue or continue to use the LEE option for your liquid oil-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(d) * * *

(5) * * *

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device). See § 63.10010(a) for further details. For PM CPMS installations (which with the exception of IGCC units, are only applicable before July 6, 2027), follow the procedures in § 63.10010(h).

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ''startup'' definition in § 63.10042.

* * * * *

■ 5. Amend § 63.10005 by revising paragraphs (a)(1), (b) introductory text, (c), (d)(2) introductory text, (h) introductory text, and (h)(1) introductory text to read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) * * *

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. Before July 6, 2027, if you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. On and after July 6, 2027, the requirements in Table 4 are not applicable, with the exception of IGCC units. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

* * * * *

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to 40 CFR 63.10007 and Table 5 to this subpart. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5I, 5D, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5I, 5D, 6, 26A, or 29 test (*e.g.,* pitot tube (delta P) readings, moisture collected in the impingers, etc.). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in 40 CFR 63.9984, provided that the following conditions are fully met:

* * * * *

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration. With the exception of IGCC units, on and after July 6, 2027, you may not demonstrate compliance with applicable filterable PM emissions limits with the use of PM CPMS or quarterly stack testing, you may only use PM CEMS.

* * * * *

(d) * * *

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS (with the exception of IGCC units, the use of PM CPMS is only allowed before July 6, 2027):

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) with the exception that on or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for any existing, new or reconstructed EGUs (this does not apply to IGCC units), and if those data demonstrate:

* * * * *

■ 6. Amend § 63.10006 by revising paragraph (a) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS before July 6, 2027 to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year. On or after July 6, 2027 you may not use PM CPMS to demonstrate compliance for liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs. This prohibition against the use of PM CPMS does not apply to IGCC units.

* * * * *

■ 7. Amend § 63.1007 by revising paragraphs (a)(3) and (c) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) * * *

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit (the use of PM CPMS is only allowed before July 6, 2027 with the exception of IGCC units), operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits. On and after July 6, 2027, you must demonstrate continuous compliance with the applicable filterable PM emission standard through the use of a PM CEMS (with the exception that IGCC units are not required to use PM CEMS and may continue to use PM CPMS). Alternatively, you may demonstrate continuous compliance with the non-Hg metals emission standard if you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

* * * * *

■ 8. Amend § 63.10010 by revising paragraphs (a) introductory text, (h) introductory text, (i) introductory text, (j), and (l) introductory text to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS (which on or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit), and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

* * * * *

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit (only applicable before July 6, 2027 unless it is for an IGCC unit), you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

* * * * *

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits (which on or after July 6, 2027 you may not use non-mercury metal HAP limits for compliance demonstrations for existing EGUs unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f)), you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. With the exception of IGCC units, on or after July 6, 2027 owners/operators of existing EGUs must comply with filterable PM emissions limits in Table 2 of this subpart and demonstrate continuous compliance using a PM CEMS unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f). Compliance with the applicable PM emissions limit in Table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

* * * * *

(j) You may choose to comply with the metal HAP emissions limits using CMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CMS and record the output of the HAP metals CMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities, and any scheduled maintenance as defined in your site-specific monitoring plan.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions and repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any out of control periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(C) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits, routine probe maintenance); and

(D) Any data recorded during periods of startup or shutdown.

(ii) You must record and report the results of HAP metals CMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods when the HAP metals CMS is out of control to completion of the corrective actions necessary to return the HAP metals CMS to operation consistent with your site-specific performance evaluation and quality control program plan.

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ''startup'' definition in § 63.10042 for your EGU.

* * * * *

■ 9. Amend § 63.10011 by revising paragraphs (b), (g)(3), and (4) introductory text to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance (with the exception of existing IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 4 p.m. CPMS operating limits do not apply), or if, for an IGCC unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.,* tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 6 procedures for establishing PM CPMS operating limits do not apply unless it is an IGCC unit.

* * * * *

(g) * * *

(3) You must report the emissions data recorded during startup and shutdown. If you are relying on paragraph (2) of the definition of startup in 40 CFR 63.10042 (only allowed before January 2, 2025), then for startup and shutdown incidents that occur on or prior to December 31, 2023, you must also report the applicable supplementary information in 40 CFR 63.10031(c)(5) in the semiannual compliance report. For startup and shutdown incidents that occur on or after January 1, 2024, you must provide the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

(4) If you choose to use paragraph (2) of the definition of ''startup'' in § 63.10042 (only allowed before January 2, 2025), and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of ''startup'' in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

* * * * *

■ 10. Section 63.10020 is amended by revising paragraphs (e) introductory text and (e)(3)(i) introductory text to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025).

* * * * *

(3) * * *

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS (except that unless it is for an IGCC unit, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, and you may not purse or continue to use the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals), you must:

* * * * *

■ 11. Section 63.10021 is amended by revising paragraphs (c) introductory text and (i) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(c) If you use PM CPMS data (only allowed before July 6, 2027 unless it is for an IGCC unit) to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.,* milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations unless it is for an IGCC unit.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq.\ 9)$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

* * * * *

(i) Before January 2, 2025, if you are relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, you must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.

■ 12. Section 63.10022 is amended by revising paragraphs (a)(2) and (3) to read as follows:

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) * * *

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test. On or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies. Since on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit, for compliance demonstrations with the applicable filterable PM limits, the Table 4 p.m. CPMS operating limits do not apply.

* * * * *

■ 13. Section 63.10023 is amended by adding introductory text to the section to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

The provisions of this section § 63.10023 are only applicable before July 6, 2027 unless it is for an IGCC unit. On or after July 6, 2027 you may not use PM CPMS, unless it is an IGCC unit, for demonstrating compliance with the filterable PM emissions limits of this subpart.

* * * * *

■ 14. Section 63.10030 is amended by revising paragraphs (e)(3), (8) introductory text, and (8)(i) introductory text to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.,* use of PM CPMS—which on or after July 6, 2027—you may not use for filterable PM compliance demonstrations, unless it is for an IGCC unit); CEMS; or a sorbent trap monitoring system.

* * * * *

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ''startup'' in § 63.10042. On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

(i) Before January 2, 2025 should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you shall include a report that identifies:

* * * * *

■ 15. Section 63.10031 is amended by revising paragraphs (a)(4), (c)(5) introductory text, (f)(2), (i), and (k) to read as follows:

§ 63.10031 What reports must I submit and when?

(a) * * *

(4) Before July 6, 2027, if you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Except for IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(c) * * *

(5) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), for each instance of startup or shutdown you shall:

* * * * *

(f) * * *

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit), you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

* * * * *

(i) If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 (only allowed before January 2, 2025), then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report.

* * * * *

(k) If you elect to demonstrate compliance using a PM CPMS (on or after July 6, 2027 you may not demonstrate compliance with filterable PM emissions limits using a PM CPMS, unless it is for an IGCC unit) or an approved HAP metals CMS, you must submit quarterly reports of your QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.

■ 16. Section 63.10032 is amended by revising paragraphs (a) introductory text and (f)(2) introductory text to read as follows:

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

* * * * *

(f) * * *

(2) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (on or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042), you must keep records of:

* * * * *

■ 17. Section 63.10042 is amended by revising the definition ''Startup'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Startup means:

(1) The first-ever firing of fuel in a boiler for the purpose of producing

electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

(2) Alternatively, prior to January 2, 2025, the period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

* * * * *

■ 18. Revise table 1 to subpart UUUUU of part 63 to read as follows:

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Mercury (Hg)	Before July 8, 2024: 4.0E–2 lb/GWh; On or after July 8, 2024: 1.3E–2 lb/GWh.	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh [4] 9.0E–2 lb/MWh [5].	Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B at appendix A–8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross output.
[5] Duct burners on natural gas; gross output.

■ 19. Revise table 2 to subpart UUUUU of part 63 to read as follows:

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits: [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
		On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh [2].	On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO_2)[4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	Before July 6, 2027: 4.0E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals ..	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn) ...	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF).	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO_2)[4].	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit.	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4].	6E–1 lb/MMBtu or 9E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
	OR		
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] Gross output.

[3] Incorporated by reference, *see* § 63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 20. Revise table 3 to subpart UUUUU of part 63 to read as follows:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in § 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	a. Before January 2, 2025 you have the option of complying using either of the following work practice standards in paragraphs (1) and (2). On or after January 2, 2025 you may not choose to use paragraph (2) of the definition of startup in § 63.10042 and the following associated work practice standards in paragraph (2).

If your EGU is . . .	You must meet the following . . .
	(1) If you choose to comply using paragraph (1) of the definition of ''startup'' in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). (2) If you choose to comply using paragraph (2) of the definition of ''startup'' in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your PM control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10021(h) and 63.10032. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.

If your EGU is . . .	You must meet the following . . .
	You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

■ 21. Revise table 4 to subpart UUUUU of part 63 to read as follows:

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

Before July 6, 2027, as stated in § 63.9991, you must comply with the applicable operating limits in table 4. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 22. Revise table 5 to subpart UUUUU of part 63 to read as follows:

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

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To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 and 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 or 5I front half temperature shall be 160° ±14 °C (320° ±25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.

		maintain the PM CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must

		each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF	Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at

		emissions concentrations	appendix A to part 63 of this chapter or ASTM D6348-03 Reapproved 2010[3] with
			(1) the following conditions when using ASTM D6348-03 Reapproved 2010:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03 Reapproved 2010, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Reapproved 2010 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 Reapproved 2010 test data to be acceptable for a target analyte, %R must be 70% ≥R ≤130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100$
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		monitoring systems	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784,[3] or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and	Sections 3.2.1 and 5.1 of appendix A of this subpart.

		maintain the CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh	Section 6 of appendix A to this subpart.

		emissions rates	
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

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[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h). With the exception of IGCC units, on or after July 6, 2027: You may not use quarterly performance emissions testing to demonstrate compliance with the filterable PM emissions standards and for existing EGUs you may not choose to comply with the total or individual HAP metals emissions limits unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

■ 23. Revise table 6 to subpart UUUUU of part 63 to read as follows:

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

Before July 6, 2027, as stated in § 63.10007, you must comply with the following requirements for establishing operating limits in table 6. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 24. Revise table 7 to subpart UUUUU of part 63 to read as follows:

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit. (On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.).	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (*e.g.,* milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2. (On or after July 6, 2027 you may not use quarterly performance testing for filterable PM compliance demonstrations, unless it is for an IGCC unit.).	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

■ 25. Revise table 8 to subpart UUUUU of part 63 to read as follows:

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

[In accordance with 40 CFR 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

You must submit the following reports . . .
1. The electronic reports required under 40 CFR 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under 40 CFR 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under 40 CFR 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under 40 CFR 63.10031(a)(4), if you elect to use a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit).
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under 40 CFR 63.10031(a)(5), if you continuously monitor SO_2 emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to the introductory text of 40 CFR 63.10031(f) and 40 CFR 63.10031(f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in 40 CFR 63.10023(b)(2)(vi).
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under 40 CFR 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO_2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to 40 CFR 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO_2 or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.

You must submit the following reports . . .
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit), according to 40 CFR 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90-group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.
11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.
12. Quarterly reports, in PDF files, that include the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in 40 CFR 63.10042 (see 40 CFR 63.10031(i)). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under 40 CFR 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS Client Tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit) or approved HAP metals CMS (as applicable), in PDF files, according to 40 CFR 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

■ 26. In appendix C to subpart UUUUU:
■ a. Revise sections 1.2, 1.3, 4.1, and 4.1.1.
■ b. Add sections 4.1.1.1 and 4.2.3.
■ c. Revise sections 5.1.1, 5.1.4, and the section heading for section 6.

The revisions and additions read as follows:

Appendix C to Subpart UUUUU of Part 63—PM Monitoring Provisions

1. General Provisions

* * * * *

1.2 *Initial Certification and Recertification Procedures.* You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in Table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to Performance Specification 11 (PS–11) in appendix B to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

1.3 *Quality Assurance and Quality Control Requirements.* You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in Procedure 2, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. However, if you have developed and are using a correlation curve, you may continue to use that curve, provided it continues to meet the acceptance criteria in PS–11 and Procedure 2 as discussed below. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1 PM CEMS. You must certify your PM CEMS according to PS–11 in appendix B to part 60 of this chapter. A PM CEMS that has been installed and certified according to PS–11 as a result of another state or federal regulatory requirement or consent decree prior to the effective date of this subpart shall be considered certified for this subpart if you can demonstrate that your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 in appendix F to part 60 of this chapter.

4.1.1.1 Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4.2 Recertification.

* * * * *

4.2.3 Beginning on July 6, 2027 you must use the value of 0.015 lb/MMBtu in place of the applicable emission standard, or emission limit, in the calculations when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

5.1.1 Required QA Tests. Following initial certification, you must conduct periodic QA testing of each primary and (if applicable) redundant backup PM CEMS. The required QA tests and the criteria that must be met are found in Procedure 2 of appendix F to part 60 of this chapter

(Procedure 2). Except as otherwise provided in section 5.1.2 of this appendix, the QA tests shall be done at the frequency specified in Procedure 2.

* * * * *

5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA. However, beginning on July 6, 2027 a value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, when determining whether the RCA and RRA are acceptable.

* * * * *

6. Data Reduction and Calculations

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■ 27. Appendix D to subpart UUUUU of part 63 is amended by adding introductory text to the appendix to read as follows:

Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, unless it is for an IGCC unit.

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