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

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.

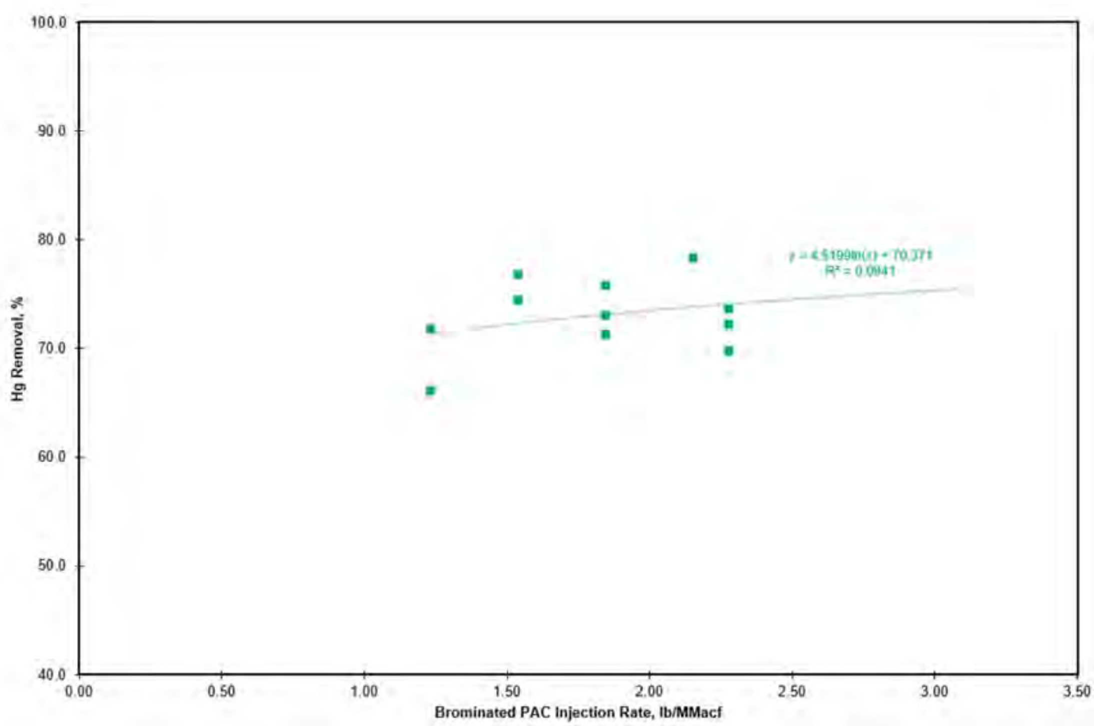
MRY Unit	Average Hourly Hg Emissions Value Achieved at Full Load (Sorbent Trap) Brominated PAC	Average Hourly Hg Emissions Value Achieved at Full Load (Sorbent Trap) Non-Brominated PAC
Unit 1	2.57	2.17

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 Error! No text of specified style in document.**-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 Error! No text of specified style in document.**-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.

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

[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.

* * * *

[Signature Follows on Next Page]

* * *

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
A Touchstone Energy® Cooperative

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

Mercury Testing Results for the MATS Residual Risk and Technology Review

Rev. 1

May 22, 2023

Project No.: A14559.013

S&L Nuclear QA Program Applicable:

☐ Yes

☒ No

55 East Monroe Street
Chicago, IL 60603-5780 USA
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Sargent & Lundy

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

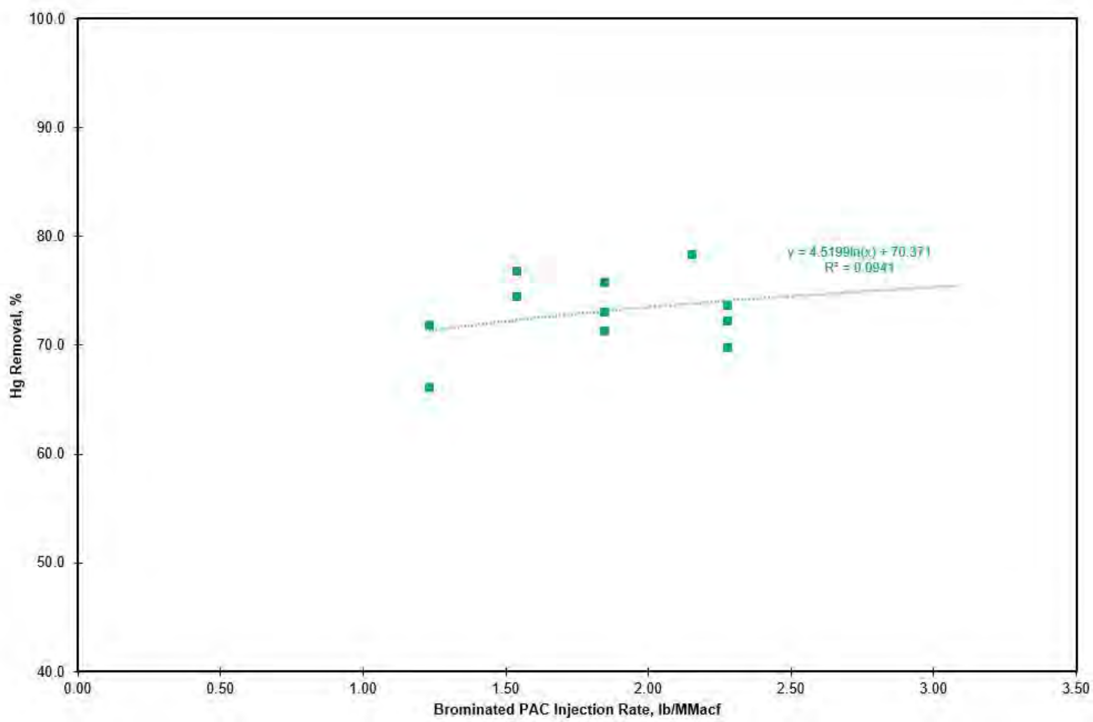
Fuel Hg Content Reference	Coal Hg Inlet (lb/TBtu)	Est. Hg Control at 4.0 lb/TBtu (%)	Est. Hg Control at 1.2 lb/TBtu (%)
EPA Technical Memo			
2023 Table 11 Docket ID. No: EPA-HQ-OAR-2018-0794[1]	7.81	48.8	84.6
2024 Table 10 Docket ID. No: EPA-HQ-OAR-2018-0794[2]	9.70	58.6	87.6
2024 MRY Unit 1 Test Campaign			
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 does not 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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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 "99^{th} 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.

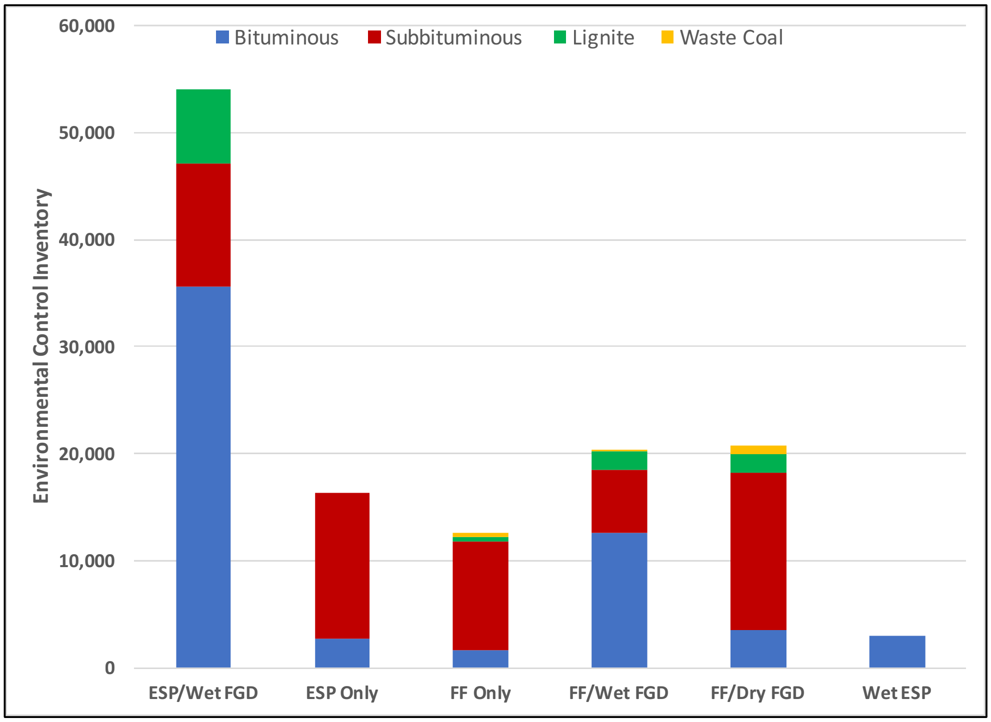

Figure 3-1. Inventory of EPA-Project 2028 Fleet by Control Technology Suite

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.

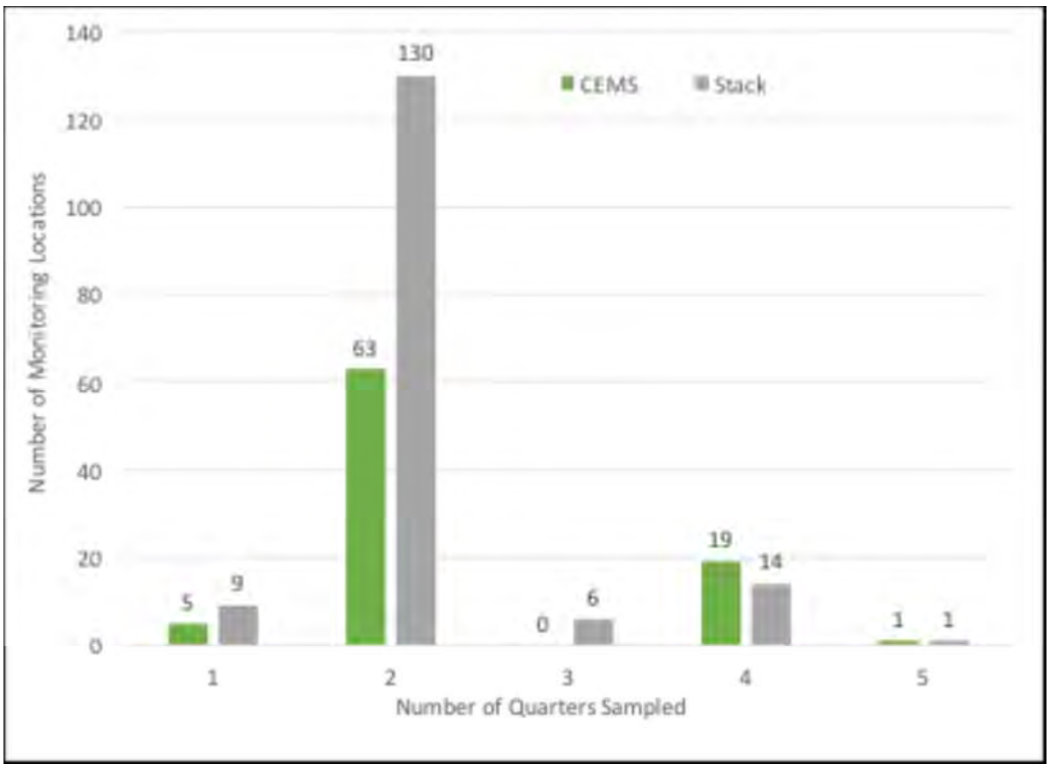

Figure 3-2. Numbers of Quarters Sampled by EPA for Use in PM Database

[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.

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[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.

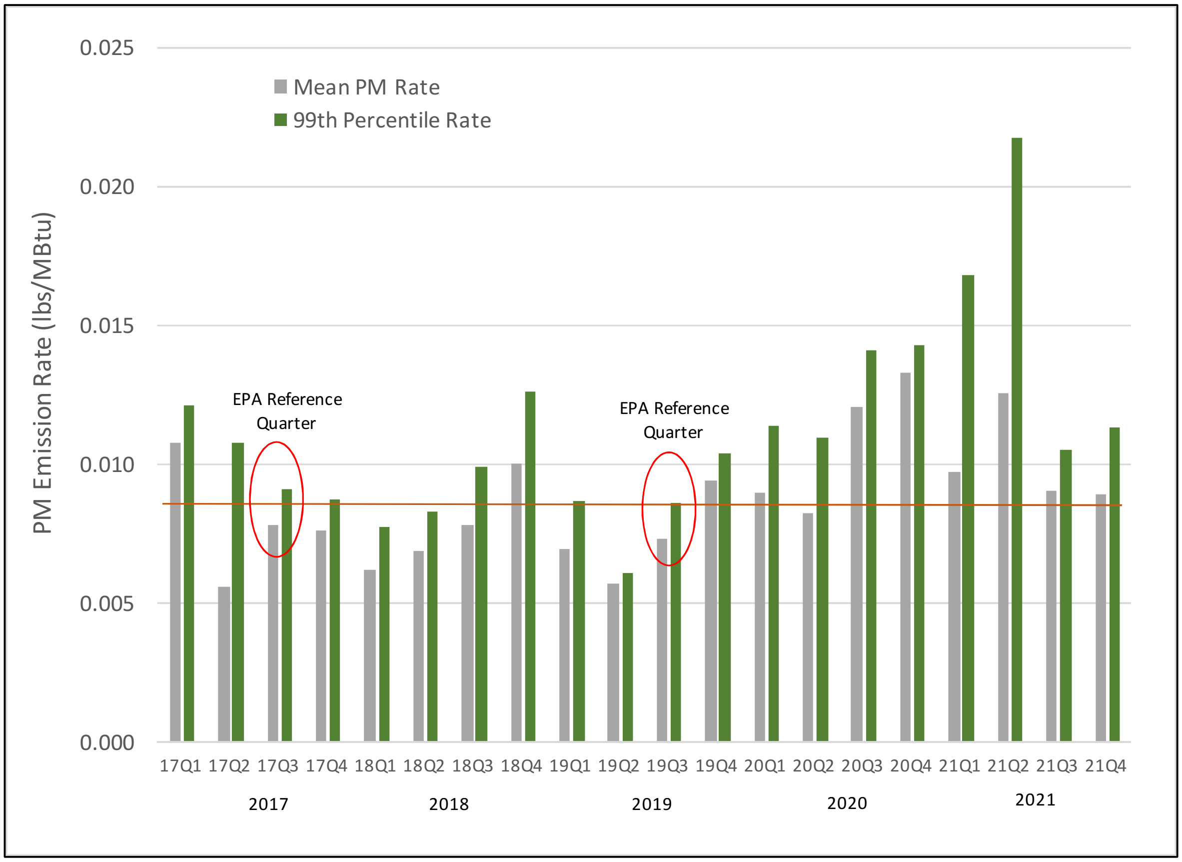

Figure 3-3. Coronado Generating Station: 20 Operating Quarters

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.

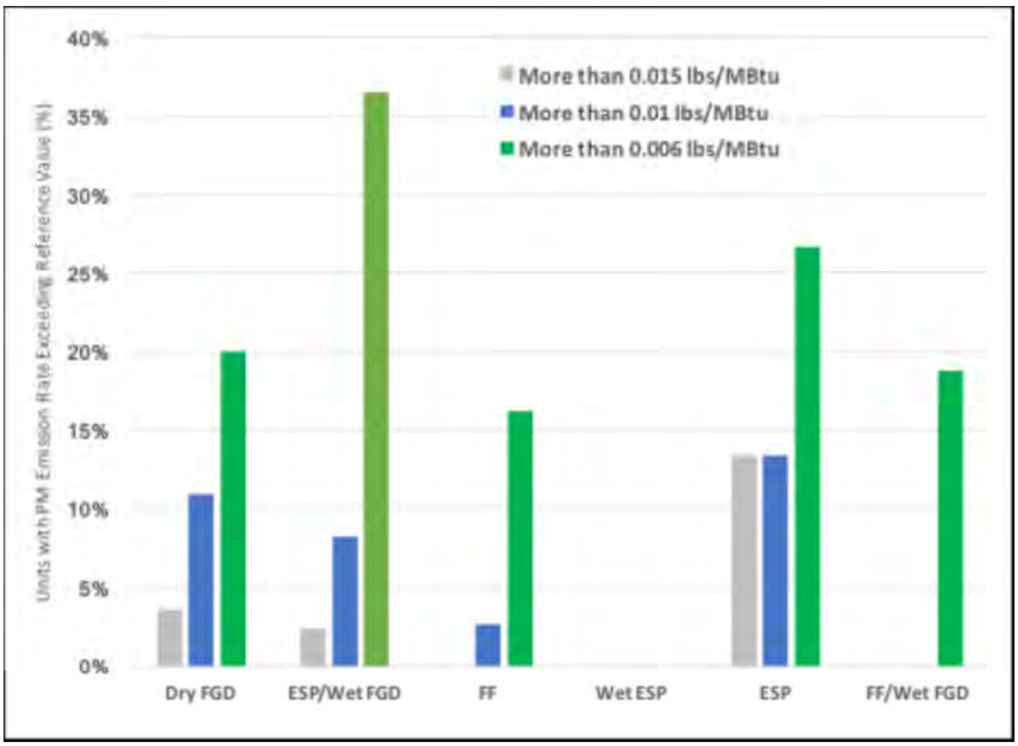

Figure 4-1. Fraction of Units Exceeding Three PM Rates: By Control Technology

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:

<u>ESP Upgrade</u>. 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.

<u>Fabric Filter O&M</u>. 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.

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

<u>Design/Compliance Margin</u>. 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.

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[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

<u>Proposed Limit: 0.010 lbs/MBtu</u>. 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.

<u>Potential Limit: 0.006 lbs/MBtu</u>. 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.

<u>ESP Upgrades.</u> 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.

[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.

[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.