No. ______

In the Supreme Court of the United States

Talen Montana, LLC and NorthWestern Corporation,

Applicants,

v.

U.S. Environmental Protection Agency and
Michael S. Regan, Administrator, U.S. Environmental Protection Agency,

Respondents.

ON EMERGENCY APPLICATION FOR STAY TO THE HONORABLE JOHN G. ROBERTS, JR.,
CHIEF JUSTICE OF THE UNITED STATES
AND CIRCUIT JUSTICE FOR THE U.S. COURT OF APPEALS FOR THE D.C. CIRCUIT

APPENDIX TO APPLICATION FOR AN IMMEDIATE STAY OF FINAL AGENCY ACTION PENDING DISPOSITION OF PETITION FOR REVIEW

Michael Drysdale
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue NW, Suite 900
Washington, DC 20005

Counsel for NorthWestern Corporation d/b/a NorthWestern Energy

Joshua B. Frank
Counsel of Record
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street NW
Washington, DC 20001
(202) 639-7748
joshua.frank@bakerbotts.com

Counsel for Talen Montana, LLC

TABLE OF APPENDICES

Page

APPENDIX E - SELECT STAY MOTION PAPERS FILED IN THE D.C. CIRCUIT CASE

APPENDIX F - SELECT DECLARATIONS FILED IN THE D.C. CIRCUIT CASE

APPENDIX A

DECISIONS BELOW

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR]

RIN 2060–AV53

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) for the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs) source category. These final amendments are the result of the EPA's review of the 2020 Residual Risk and Technology Review (RTR). The changes, which were proposed under the technology review in April 2023, include amending the filterable particulate matter (fPM) surrogate emission standard for non-mercury metal hazardous air pollutants (HAP) for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, and the mercury (Hg) emission standard for lignite-fired EGUs. Additionally, the EPA is finalizing a change to the definition of ''startup.'' The EPA did not propose, and is not finalizing, any changes to the 2020 Residual Risk Review.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain material listed in the rule was approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The U.S. Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0794. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *https://www.regulations.gov,* or in hard copy at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action contact Sarah Benish, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5620; and email address: *benish.sarah@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

APH air preheater
Btu British Thermal Units
CAA Clean Air Act
CEMS continuous emission monitoring system
EGU electric utility steam generating unit
EIA Energy Information Administration
ESP electrostatic precipitator
FF fabric filter
FGD flue gas desulfurization
fPM filterable particulate matter
GWh gigawatt-hour
HAP hazardous air pollutant(s)
HCl hydrogen chloride
HF hydrogen fluoride
Hg mercury
Hg^0 elemental Hg vapor
Hg^{2+} divalent Hg
$HgCl_2$ mercuric chloride
Hg_p particulate bound Hg
HQ hazard quotient
ICR Information Collection Request
IGCC integrated gasification combined cycle
IPM Integrated Planning Model
IRA Inflation Reduction Act
lb pounds
LEE low emitting EGU
MACT maximum achievable control technology
MATS Mercury and Air Toxics Standards
MMacf million actual cubic feet
MMBtu million British thermal units of heat input
MW megawatt
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NO_X nitrogen oxides
NRECA National Rural Electric Cooperative Association
OMB Office of Management and Budget
PM particulate matter
$PM_{2.5}$ fine particulate matter
PM CEMS particulate matter continuous emission monitoring systems
REL reference exposure level
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RIN Regulatory Information Number
RTR residual risk and technology review
SC–CO_2 social cost of carbon
SO_2 sulfur dioxide
TBtu trillion British thermal units of heat input
tpy tons per year
UMRA Unfunded Mandates Reform Act
WebFIRE Web Factor Information Retrieval System

Background information. On April 24, 2023, the EPA proposed revisions to the Coal- and Oil-Fired EGU NESHAP based on our review of the 2020 RTR. In this action, we are finalizing revisions to the rule, commonly known as the Mercury and Air Toxics Standards (MATS). We summarize some of the more significant comments regarding the proposed rule that were received during the public comment period and provide our responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* Docket ID No. EPA–HQ–OAR–2018–0794. A ''track changes'' version of the regulatory language that incorporates the changes in this action is available in the docket.

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Background and Purpose of the Regulatory Action

Exposure to hazardous air pollutants (''HAP,'' sometimes known as toxic air pollution, including Hg, chromium, arsenic, and lead) can cause a range of adverse health effects including harming people's central nervous system; damage to their kidneys; and cancer. These adverse effects can be particularly acute for communities living near sources of HAP. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, the EPA is required to set standards based on maximum achievable control technology (known as ''MACT'' standards) for major sources [1] of HAP that ''require the maximum degree of reduction in emissions of the hazardous air pollutants . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable.'' 42 U.S.C. 7412(d)(2). The EPA is further required to ''review, and revise'' those standards every 8 years ''as necessary (taking into account developments in practices, processes, and control technologies).'' *Id.* 7412(d)(6).

On January 20, 2021, President Biden signed Executive Order 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis'' (86 FR 7037; January 25, 2021). The executive order, among other things, instructed the EPA to review the 2020 final rule titled *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil- Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review* (85 FR 31286; May 22, 2020) (2020 Final Action) and to consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action. The 2020 Final Action included two parts: (1) a finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112; and (2) the RTR for the 2012 MATS Final Rule.

The EPA reviewed both parts of the 2020 Final Action. The results of the EPA's review of the first part, finding it is appropriate and necessary to regulate EGUs under CAA section 112, were proposed on February 9, 2022 (87 FR 7624) (2022 Proposal) and finalized on March 6, 2023 (88 FR 13956). In the 2022 Proposal, the EPA also solicited information on the performance and cost of new or improved technologies that control HAP emissions, improved methods of operation, and risk-related information to further inform the EPA's review of the second part, the 2020 MATS RTR. The EPA proposed amendments to the RTR on April 24, 2023 (88 FR 24854) (2023 Proposal) and this action finalizes those amendments and presents the final results of the EPA's review of the MATS RTR.

2. Summary of Major Provisions of the Regulatory Action

Coal- and oil-fired EGUs remain one of the largest domestic emitters of Hg and many other HAP, including many of the non-Hg HAP metals—including lead, arsenic, chromium, nickel, and cadmium—and hydrogen chloride (HCl). Exposure to these HAP, at certain levels and duration, is associated with a variety of adverse health effects. In the 2012 MATS Final Rule, the EPA established numerical standards for Hg, non-Hg HAP metals, and acid gas HAP emissions from coal- and oil-fired EGUs. The EPA also established work practice standards for emissions of organic HAP. To address emissions of non-Hg HAP

[1] The term ''major source'' means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. 42 U.S.C. 7412(a)(1).

metals, the EPA established individual emission limits for each of the 10 non-Hg HAP metals [2] emitted from coal- and oil- fired EGUs. Alternatively, affected sources could meet an emission standard for ''total non-Hg HAP metals'' by summing the emission rates of each of the non-Hg HAP metals or meet a fPM emission standard as a surrogate for the non-Hg HAP metals. For existing coal-fired EGUs, almost every unit has chosen to demonstrate compliance with the non-Hg HAP metals surrogate fPM emission standard of 0.030 pounds (lb) of fPM per million British thermal units of heat input (lb/MMBtu).

Pursuant to CAA section 112(d)(6), the EPA reviewed developments in the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a fPM emission standard that is more stringent than 0.030 lb/MMBtu and the other statutory factors. Based on that review, the EPA is finalizing, as proposed, a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu. This strengthened standard will ensure that the entire fleet of coal-fired EGUs is performing at the fPM pollution control levels currently achieved by the vast majority of regulated units. The EPA further concludes that it is the lowest level currently compatible with the use of PM CEMS for demonstrating compliance.

Relatedly, the EPA is also finalizing a revision to the requirements for demonstrating compliance with the revised fPM emission standard. Currently, affected EGUs that do not qualify for the low emitting EGU (LEE) program for fPM [3] can demonstrate compliance with the fPM standard either by conducting quarterly performance testing (*i.e.,* quarterly stack testing) or by using particulate matter (PM) continuous emission monitoring systems (PM CEMS). PM CEMS confer significant benefits, including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. After considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and the measurement capabilities of PM CEMS, as well as the many benefits of using PM CEMS, the EPA is finalizing, as proposed, a requirement that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. As the EPA explained in the 2023 Proposal, by requiring facilities to use PM CEMS, the current compliance method for the LEE program becomes superfluous since LEE is an optional program in which stack testing occurs infrequently, and the revised fPM limit is below the current fPM LEE program limit. Therefore, the EPA is finalizing, as proposed, the removal of the fPM LEE program.

Based on comments received during the public comment period, the EPA is not removing, but instead revising the alternative emission limits for the individual non-Hg HAP metals such as lead, arsenic, chromium, nickel, and cadmium and for the total non-Hg HAP metals proportional to the finalized fPM emission limit of 0.010 lb/MMBtu.[4] Owners and operators of EGUs seeking to use these alternative standards must request and receive approval to use a HAP metal continuous monitoring system (CMS) as an alternative test method under 40 CFR 63.7(f).

The EPA is also finalizing, as proposed, a more protective Hg emission standard for existing lignite-fired EGUs, requiring that such lignite-fired EGUs meet the same Hg emission standard as EGUs firing other types of coal (*i.e.,* bituminous and subbituminous), which is 1.2 lb of Hg per trillion British thermal units of heat input (lb/TBtu) or an alternative output-based standard of 0.013 lb per gigawatt-hour (lb/GWh). Finally, the EPA is finalizing, as proposed, the removal of the second option for defining the startup period for MATS-affected EGUs.

The EPA did not propose and is not finalizing modifications to the HCl emission standard (nor the alternative sulfur dioxide (SO_2) emission standard), which serves as a surrogate for all acid gas HAP (HCl, hydrogen fluoride (HF), selenium dioxide (SeO_2)) for existing coal-fired EGUs. The EPA proposed to require PM CEMS for existing integrated gasification combined cycle (IGCC) EGUs but is not finalizing this requirement due to technical issues calibrating CEMS on these types of EGUs and the related fact that fPM emissions from IGCCs are very low.

In establishing the final standards, as discussed in detail in sections IV., V., VI., and VII. of this preamble, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112. Separately, pursuant to Executive Order 12866 and Executive Order 14904, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is available in the docket, and is briefly summarized in sections I.A.3. and IX. of this preamble.

3. Costs and Benefits

In accordance with Executive Order 12866 and 14094, the EPA prepared a Regulatory Impact Analysis (RIA). The RIA presents estimates of the emission, cost, and benefit impacts of this final rulemaking for the 2028 to 2037 period; those estimates are summarized in this section.

The power industry's compliance costs are represented in the RIA as the projected change in electric power generation costs between the baseline and final rule scenarios. The quantified emission estimates presented in the RIA include changes in pollutants directly covered by this rule, such as Hg and non-Hg HAP metals, and changes in other pollutants emitted from the power sector due to the compliance actions projected under this final rule. The cumulative projected national-level emissions reductions over the 2028 to 2037 period under the finalized requirements are presented in table 1. The supporting details for these estimates can be found in the RIA.

BILLING CODE 6560–50–P

[2] The ten non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[3] In order to qualify for fPM LEE status, an EGU must demonstrate that its fPM emission rate is below 50 percent of standard (or 0.015 lb/MMBtu) from quarterly stack tests for 3 consecutive years. Once a source achieves LEE status for fPM, the source must conduct stack testing every 3 years to demonstrate that its emission rate remains below 50 percent of the standard.

[4] The emission limits for the individual non-Hg HAP metals and the total non-Hg HAP metals have been reduced by two-thirds, consistent with the revision of the fPM emission limit from 0.030 lb/MMBtu to 0.010 lb/MMBtu.

Table 1. Cumulative Projected Emissions Reductions under the Final Rule, 2028 to 2037[a]

Pollutant	Emissions Reductions
Hg (pounds)	9,500
$PM_{2.5}$ (tons)	5,400
SO_2 (tons)	770
NO_x (tons)	220
CO_2 (thousand tons)	650
non-Hg HAP metals (tons)[b]	49

[a] Values rounded to two significant figures.

[b] The non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

The EPA expects that emission reductions under the final rulemaking will result in reduced exposure to Hg and non-Hg HAP metals. The EPA also projects health benefits due to improvements in particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$) and ozone and climate benefits from reductions in carbon dioxide (CO_2) emissions. The EPA also anticipates benefits from the increased transparency to the public, the assurance that standards are being met continuously, and the accelerated identification of anomalous emissions due to requiring PM CEMS in this final rule.

The EPA estimates negative net monetized benefits of this rule (see table 2 below). However, the benefit estimates informing this result represent only a partial accounting of the potential benefits of this final rule. Several categories of human welfare and climate benefits are unmonetized and are thus not directly reflected in the quantified net benefit estimates (see section IX.B. in this preamble and section 4 of the RIA for more details). In particular, estimating the economic benefits of reduced exposure to HAP generally has proven difficult for a number of reasons: it is difficult to undertake epidemiologic studies that have sufficient power to quantify the risks associated with HAP exposures experienced by U.S. populations on a daily basis; data used to estimate exposures in critical microenvironments are limited; and there remains insufficient economic research to support valuation of HAP benefits made even more challenging by the wide array of HAP and possible HAP effects.[5] In addition, due to data limitations, the EPA is also unable to quantify potential emissions impacts or monetize potential benefits from continuous monitoring requirements.

The present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this rulemaking over the 2028 to 2037 period in 2019 dollars are shown in table 2. In this table, results are presented using a 2 percent discount rate. Results under other discount rates and supporting details for the estimates can be found in the RIA.

[5] See section II.B.2. for discussion of the public health and environmental hazards associated with HAP emissions from coal- and oil-fired EGUs and discussion on the limitations to monetizing and quantifying benefits from HAP reductions. See also *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023).

Table 2. Projected Benefits, Costs, and Net Benefits under the Final Rule, 2028 to 2037 (millions of 2019 dollars, discounted to 2023)[a]

	2% Discount Rate	
	PV	EAV
Ozone- and $PM_{2.5}$-related Health Benefits	300	33
Climate Benefits[b]	130	14
Compliance Costs	860	96
Net Benefits[c]	-440	-49
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually	
	Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually	
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate.

[c] Several categories of benefits remain unmonetized and are thus not reflected in the table.

BILLING CODE 6560–50–C

The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discusses in section II.A. and sections IV. through VII. below.

B. Does this action apply to me?

Regulated entities. The source category that is the subject of this action is coal- and oil-fired EGUs regulated by NESHAP under 40 CFR part 63, subpart UUUUU, commonly known as MATS. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU source category are 221112, 221122, and 921150. This list of NAICS codes is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will also be available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at: *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same website.

Additional information is available on the RTR website at *https://www.epa.gov/stationary-sources-air-pollution/risk-and-technology-review-national-emissions-standards-hazardous.* This information includes an overview of the RTR program and links to project websites for the RTR source categories.

D. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by July 8, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure that was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave., NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate

General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. Statutory Language

The statutory authority for this action is provided by sections 112 and 301 of the CAA, as amended (42 U.S.C. 7401 *et seq.*). Section 112 of the CAA establishes a multi-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, during the first stage, Congress directed the EPA to establish technology-based standards to ensure that all major sources control HAP emissions at the level achieved by the best-performing sources, referred to as the MACT. After the first stage, Congress directed the EPA to review those standards periodically to determine whether they should be strengthened. Within 8 years after promulgation of the standards, the EPA must evaluate the MACT standards to determine whether the emission standards should be revised to address any remaining risk associated with HAP emissions. This second stage is commonly referred to as the ''residual risk review.'' In addition, the CAA also requires the EPA to review standards set under CAA section 112 on an ongoing basis no less than every 8 years and revise the standards as necessary taking into account any ''developments in practices, processes, and control technologies.'' This review is commonly referred to as the ''technology review,'' and is the primary subject of this final rule. The discussion that follows identifies the most relevant statutory sections and briefly explains the contours of the methodology used to implement these statutory requirements.

In the first stage of the CAA section 112 standard-setting process, the EPA promulgates technology-based standards under CAA section 112(d) for categories of sources identified as emitting one or more of the HAP listed in CAA section 112(b). Sources of HAP emissions are either major sources or area sources, and CAA section 112 establishes different requirements for major source standards and area source standards. ''Major sources'' are those that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. All other sources are ''area sources.'' For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect ''*the maximum degree of reduction* in emissions of the [HAP] subject to this section (*including a prohibition on such emissions, where achievable*) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable.'' (emphasis added). These standards are commonly referred to as MACT standards. CAA section 112(d)(3) establishes a minimum control level for MACT standards, known as the MACT ''floor.'' [6] In certain instances, as provided in CAA section 112(h), the EPA may set work practice standards in lieu of numerical emission standards. The EPA must also consider control options that are more stringent than the floor. Standards more stringent than the floor are commonly referred to as ''beyond-the-floor'' standards. For area sources, CAA section 112(d)(5) allows the EPA to set standards based on generally available control technologies or management practices (GACT standards) in lieu of MACT standards.[7]

For categories of major sources and any area source categories subject to MACT standards, the next stage in standard-setting focuses on identifying and addressing any remaining (*i.e.,* ''residual'') risk pursuant to CAA section 112(f)(2). The residual risk review requires the EPA to update standards if needed to provide an ample margin of safety to protect public health.

Concurrent with that review, and then at least every 8 years thereafter, CAA section 112(d)(6) requires the EPA to review standards promulgated under CAA section 112 and revise them ''as necessary (taking into account developments in practices, processes, and control technologies).'' *See Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 189 (D.C. Cir. 2011) (''Though EPA must review and revise standards 'no less often than every eight years,' 42 U.S.C. 7412(d)(6), nothing prohibits EPA from reassessing its standards more often.''). In conducting this review, which we call the ''technology review,'' the EPA is not required to recalculate the MACT floors that were established in earlier rulemakings. *Natural Resources Defense Council (NRDC)* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008); *Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). *See e.g., Nat'l Ass'n for Surface Finishing,* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA is required to address regulatory gaps, such as missing MACT standards for listed air toxics known to be emitted from the source category. *Louisiana Environmental Action Network (LEAN)* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020). The residual risk review and the technology review are distinct requirements and are both mandatory.

In this action, the EPA is finalizing amendments to the MACT standards based on two independent sources of authority: (1) its review of the 2020 Final Action's risk and technology review pursuant to the EPA's statutory authority under CAA section 112, and (2) the EPA's inherent authority to reconsider previous decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *see also Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983).

2. Statutory Structure and Legislative History

In addition to the text of the specific subsections of CAA section 112 discussed above, the statutory structure and legislative history of CAA section 112 further support the EPA's authority to take this action. Throughout CAA section 112 and its legislative history, Congress made clear its intent to quickly secure large reductions in the volume of HAP emissions from stationary sources based on technological developments in control technologies because of its recognition of the hazards to public health and the environment that result from exposure to such emissions. CAA section 112 and its legislative history also reveal Congress's understanding that fully characterizing the risks posed by HAP emissions was exceedingly difficult. Thus, Congress purposefully replaced a regime that required the EPA to make an assessment of risk in the first instance, with one in which Congress determined risk existed and directed the EPA to make swift and substantial reductions based upon the most stringent standards technology could achieve.

Specifically, in 1990, Congress radically transformed section 112 of the CAA and its treatment of HAP through the Clean Air Act Amendments, by

[6] Specifically, for existing sources, the MACT ''floor'' shall not be less stringent than the average emission reduction achieved by the best performing 12 percent of existing sources. 42 U.S.C. 7412(d)(3). For new sources MACT shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source. *Id.*

[7] For categories of area sources subject to GACT standards, there is no requirement to address residual risk, but, similar to the major source categories, the technology review is required.

amending CAA section 112 to be a technology-driven standard setting provision as opposed to the risk-based one that Congress initially promulgated in the 1970 CAA. The legislative history of the 1990 Amendments indicates Congress's dissatisfaction with the EPA's slow pace addressing HAP under the 1970 CAA: ''In theory, [hazardous air pollutants] were to be stringently controlled under the existing Clean Air Act section 112. However, . . . only 7 of the hundreds of potentially hazardous air pollutants have been regulated by EPA since section 112 was enacted in 1970.'' H.R. Rep. No. 101–490, at 315 (1990); see also *id.* at 151 (noting that in 20 years, the EPA's establishment of standards for only seven HAP covered ''a small fraction of the many substances associated . . . with cancer, birth defects, neurological damage, or other serious health impacts.'').

In enacting the 1990 Amendments with respect to the control of HAP, Congress noted that ''[p]ollutants controlled under [section 112] tend to be less widespread than those regulated [under other sections of the CAA], but are often associated with more serious health impacts, such as cancer, neurological disorders, and reproductive dysfunctions.'' *Id.* at 315. In its substantial 1990 Amendments, Congress itself listed 189 HAP (CAA section 112(b)) and set forth a statutory structure that would ensure swift regulation of a significant majority of these HAP emissions from stationary sources. Specifically, after defining major and area sources and requiring the EPA to list all major sources and many area sources of the listed pollutants (CAA section 112(c)), the new CAA section 112 required the EPA to establish technology-based emission standards for listed source categories on a prompt schedule and to revisit those technology-based standards every 8 years on an ongoing basis (CAA section 112(d) (emission standards); CAA section 112(e) (schedule for standards and review)). The 1990 Amendments also obligated the EPA to conduct a one-time evaluation of the residual risk within 8 years of promulgation of technology-based standards. CAA section 112(f)(2).

In setting the standards, CAA section 112(d) requires the EPA to establish technology-based standards that achieve the ''maximum degree of reduction,'' ''including a prohibition on such emissions where achievable.'' CAA section 112(d)(2). Congress specified that the maximum degree of reduction must be at least as stringent as the average level of control achieved in practice by the best performing sources in the category or subcategory based on emissions data available to the EPA at the time of promulgation. This technology-based approach enabled the EPA to swiftly set standards for source categories without determining the risk or cost in each specific case, as the EPA had done prior to the 1990 Amendments. In other words, this approach to regulation quickly required that all major sources and many area sources of HAP meet an emission standard consistent with the top performers in each category, which had the effect of obtaining immediate reductions in the volume of HAP emissions from stationary sources. The statutory requirement that sources obtain levels of emission limitation that have actually been achieved by existing sources, instead of levels that could theoretically be achieved, inherently reflects a built-in cost consideration.[8]

Further, after determining the minimum stringency level of control, or MACT floor, CAA section 112(d)(2) directs the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable)'' that the EPA determines are achievable after considering the cost of achieving such standards and any non-air-quality health and environmental impacts and energy requirements of additional control. In doing so, the statute further specifies in CAA section 112(d)(2) that the EPA should consider requiring sources to apply measures that, among other things, ''reduce the volume of, or eliminate emissions of, such pollutants . . . '' (CAA section 112(d)(2)(A)), ''enclose systems or processes to eliminate emissions'' (CAA section 112(d)(2)(B)), and ''collect, capture, or treat such pollutants when released . . . '' (CAA section 112(d)(2)(C)). The 1990 Amendments also built in a regular review of new technologies and a one-time review of risks that remain after imposition of MACT standards. CAA section 112(d)(6) requires the EPA to evaluate every NESHAP no less often than every 8 years to determine whether additional control is necessary after taking into consideration ''developments in practices, processes, and control technologies,'' separate from its obligation to review residual risk. CAA section 112(f) requires the EPA to ensure within 8 years of promulgating a NESHAP that the risks are acceptable and that the MACT standards provide an ample margin of safety.

The statutory requirement to establish technology-based standards under CAA section 112 eliminated the requirement for the EPA to identify hazards to public health and the environment in order to justify regulation of HAP emissions from stationary sources, reflecting Congress's judgment that such emissions are inherently dangerous. See S. Rep. No. 101–228, at 148 (''The MACT standards are based on the performance of technology, and not on the health and environmental effects of the [HAP].''). The technology review required in CAA section 112(d)(6) further mandates that the EPA continually reassess standards to determine if additional reductions can be obtained, without evaluating the specific risk associated with the HAP emissions that would be reduced. Notably, Congress required the EPA to conduct the CAA section 112(d)(6) review of what additional reductions may be obtained based on new technology even after the EPA has conducted the one-time CAA section 112(f)(2) risk review and determined that the existing standard will protect the public with an ample margin of safety. The two requirements are distinct, and both are mandatory.

B. What is the Coal- and Oil-Fired EGU source category and how does the NESHAP regulate HAP emissions from the source category?

1. Summary of Coal- and Oil-Fired EGU Source Category and NESHAP Regulations

The EPA promulgated the Coal- and Oil-Fired EGU NESHAP (commonly referred to as MATS) on February 16, 2012 (77 FR 9304) (2012 MATS Final Rule). The standards are codified at 40 CFR part 63, subpart UUUUU. The coal- and oil-fired electric utility industry consists of facilities that burn coal or oil located at both major and area sources of HAP emissions. An existing affected source is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began

[8] Congress recognized as much: ''The Administrator may take the cost of achieving the maximum emission reduction and any non-air quality health and environmental impacts and energy requirements into account when determining the emissions limitation which is achievable for the sources in the category or subcategory. Cost considerations are reflected in the selection of emissions limitations which have been achieved in practice (rather than those which are merely theoretical) by sources of a similar type or character.'' A Legislative History of the Clean Air Act Amendments of 1990 (CAA Legislative History), Vol 5, pp. 8508–8509 (CAA Amendments of 1989; p. 168–169; Report of the Committee on Environment and Public Works S. 1630).

after May 3, 2011. An EGU is a fossil fuel-fired combustion unit of more than 25 megawatts (MW) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale is also considered an EGU. The 2012 MATS Final Rule defines additional terms for determining rule applicability, including, but not limited to, definitions for ''coal-fired electric utility steam generating unit,'' ''oil-fired electric utility steam generating unit,'' and ''fossil fuel-fired.'' In 2028, the EPA expects the source category covered by this MACT standard to include 314 coal-fired steam generating units (140 GW at 157 facilities), 58 oil-fired steam generating units (23 GW at 35 facilities), and 5 IGCC units (0.8 GW at 2 facilities).

For coal-fired EGUs, the 2012 MATS Final Rule established standards to limit emissions of Hg, acid gas HAP (*e.g.,* HCl, HF), non-Hg HAP metals (*e.g.,* nickel, lead, chromium), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Emission standards for HCl serve as a surrogate for the acid gas HAP, with an alternate standard for SO_2 that may be used as a surrogate for acid gas HAP for those coal-fired EGUs with flue gas desulfurization (FGD) systems and SO_2 CEMS installed and operational. Standards for fPM serve as a surrogate for the non-Hg HAP metals. Work practice standards limit formation and emissions of organic HAP.

For oil-fired EGUs, the 2012 MATS Final Rule established standards to limit emissions of HCl and HF, total HAP metals (*e.g.,* Hg, nickel, lead), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Standards for fPM also serve as a surrogate for total HAP metals, with standards for total and individual HAP metals provided as alternative equivalent standards. Work practice standards limit formation and emissions of organic HAP.

MATS includes standards for existing and new EGUs for eight subcategories: three for coal-fired EGUs, one for IGCC EGUs, one for solid oil-derived fuel-fired EGUs (*i.e.,* petroleum coke-fired), and three for liquid oil-fired EGUs. EGUs in seven of the subcategories are subject to numeric emission limits for all the pollutants described above except for organic HAP (limited-use liquid oil-fired EGUs are not subject to numeric emission limits). Emissions of organic HAP are regulated by a work practice standard that requires periodic combustion process tune-ups. EGUs in the subcategory of limited-use liquid oil-fired EGUs with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input are also subject to a work practice standard consisting of periodic combustion process tune-ups but are not subject to any numeric emission limits. Emission limits for existing EGUs and additional information of the history and other requirements of the 2012 MATS Final Rule are available in the 2023 Proposal preamble (88 FR 24854).

2. Public Health and Environmental Hazards Associated With Emissions From Coal- and Oil-Fired EGUs

Coal- and oil-fired EGUs are a significant source of numerous HAP that are associated with adverse effects to human health and the environment, including Hg, HF, HCl, selenium, arsenic, chromium, cobalt, nickel, hydrogen cyanide, beryllium, and cadmium emissions. Hg is a persistent and bioaccumulative toxic metal that, once released from power plants into the ambient air, can be readily transported and deposited to soil and aquatic environments where it is transformed by microbial action into methylmercury.[9] Methylmercury bioaccumulates in the aquatic food web eventually resulting in highly concentrated levels of methylmercury within the larger and longer-living fish (*e.g.,* carp, catfish, trout, and perch), which can then be consumed by humans.

Of particular concern is chronic prenatal exposure via maternal consumption of foods containing methylmercury. Elevated exposure has been associated with developmental neurotoxicity and manifests as poor performance on neurobehavioral tests, particularly on tests of attention, fine motor function, language, verbal memory, and visual-spatial ability. Evidence also suggests potential for adverse effects on the cardiovascular system, adult nervous system, and immune system, as well as potential for causing cancer. Because the impacts of the neurodevelopmental effects of methylmercury are greatest during periods of rapid brain development, developing fetuses, infants, and young children are particularly vulnerable. Children born to populations with high fish consumption (*e.g.,* people consuming fish as a dietary staple) or impaired nutritional status may be especially susceptible to adverse neurodevelopmental outcomes. These dietary and nutritional risk factors are often particularly pronounced in vulnerable communities with people of color and low-income populations that have historically faced economic and environmental injustice and are overburdened by cumulative levels of pollution. In addition to adverse neurodevelopmental effects, there is evidence that exposure to methylmercury in humans and animals can have adverse effects on both the developing and adult cardiovascular system.

Along with the human health hazards associated with methylmercury, it is well-established that birds and mammals are also exposed to methylmercury through fish consumption (Mercury Study). At higher levels of exposure, the harmful effects of methylmercury include slower growth and development, reduced reproduction, and premature mortality. The effects of methylmercury on wildlife are variable across species but have been observed in the environment for numerous avian species and mammals including polar bears, river otters, and panthers.

EGUs are also the largest source of HCl, HF, and selenium emissions, and are a major source of metallic HAP emissions including arsenic, chromium, nickel, cobalt, and others. Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* pneumonitis, decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys) and alimentary effects (such as nausea and vomiting). As of 2021, three of the key metal HAP emitted by EGUs (arsenic, chromium, and nickel) have been classified as human carcinogens, while three others (cadmium, selenium, and lead) are classified as probable human carcinogens. Overall (metal and nonmetal), the EPA has classified four of the HAP emitted by EGUs as human carcinogens and five as probable human carcinogens.

While exposure to HAP is associated with a variety of adverse effects, quantifying the economic value of these impacts remains challenging. Epidemiologic studies, which report a central estimate of population-level risk, are generally used in an air pollution benefits assessment to estimate the number of attributable cases of events. Exposure to HAP is typically more uneven and more highly concentrated among a smaller number of individuals than exposure to criteria pollutants.

[9] U.S. EPA. 1997, Mercury Study Report to Congress, EPA–452/R–97–003 (December 1997); *see also* 76 FR 24976 (May 3, 2011); 80 FR 75029 (December 1, 2015).

Hence, conducting an epidemiologic study for HAP is inherently more challenging; for starters, the small population size means such studies often lack sufficient statistical power to detect effects (particularly outcomes like cancer, for which there can exist a multi-year time lag between exposure and the onset of the disease). By contrast, sufficient power generally exists to detect effects for criteria pollutants because exposures are ubiquitous and a variety of methods exist to characterize this exposure over space and time.

For the reasons noted above, epidemiologic studies do not generally exist for HAP. Instead, the EPA tends to rely on experimental animal studies to identify the range of effects which may be associated with a particular HAP exposure. Human controlled clinical studies are often limited due to ethical barriers (*e.g.,* knowingly exposing someone to a carcinogen). Generally, robust data are needed to quantify the magnitude of expected adverse impacts from varying exposures to a HAP. These data are necessary to provide a foundation for quantitative benefits analyses but are often lacking for HAP, made even more challenging by the wide array of HAP and possible noncancer HAP effects.

Finally, estimating the economic value of HAP is made challenging by the human health endpoints affected. For example, though EPA can quantify the number and economic value of HAP-attributable deaths resulting from cancer, it is difficult to monetize the value of reducing an individual's potential cancer risk attributable to a lifetime of HAP exposure. An alternative approach of conducting willingness to pay studies specifically on risk reduction may be possible, but such studies have not yet been pursued.

C. Summary of the 2020 Residual Risk Review

As required by CAA section 112(f)(2), the EPA conducted the residual risk review (2020 Residual Risk Review) in 2020, 8 years after promulgating the 2012 MATS Final Rule, and presented the results of the review, along with our decisions regarding risk acceptability, ample margin of safety, and adverse environmental effects, in the 2020 Final Action. The results of the risk assessment are presented briefly in table 3 of this document, and in more detail in the document titled *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule* (risk document for the final rule), available in the docket (Document ID No. EPA–HQ–OAR–2018–0794–4553). The EPA summarized the results and findings of the 2020 Residual Risk Review in the preamble of the 2023 Proposal (88 FR 24854), and additional information concerning the residual risk review can be found in our *National-Scale Mercury Risk Estimates for Cardiovascular and Neurodevelopmental Outcomes for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Finding; Notice of Proposed Rulemaking* memorandum (Document ID No. EPA–HQ–OAR–2018–0794–4605).

BILLING CODE 6560–50–P

Table 3. Coal- and Oil-Fired EGU Inhalation Risk Assessment Results in the 2020 Final Action (85 FR 31286; May 22, 2020)

Number of Facilities[1]	Maximum Individual Cancer Risk (in 1 million)[2]		Population at Increased Risk of Cancer ≥ 1-in-1 million		Annual Cancer Incidence (cases per year)		Maximum Chronic Noncancer TOSHI[3]		Maximum Screening Acute Noncancer HQ[4]
322	Based on . . .		Based on . . .		Based on . . .		Based on . . .		Based on Actual Emissions Level
	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	
	9	10	193,000	636,000	0.04	0.1	0.2	0.4	HQ_{REL} = 0.09 (arsenic)

[1] Number of facilities evaluated in the risk analysis. At the time of the risk analysis there were an estimated 323 facilities in the Coal- and Oil-Fired EGU source category; however, one facility is located in Guam, which was beyond the geographic range of the model used to estimate risks. Therefore, the Guam facility was not modeled and the emissions for that facility were not included in the assessment.

[2] Maximum individual excess lifetime cancer risk due to HAP emissions from the source category.

[3] Maximum target organ-specific hazard index (TOSHI). The target organ systems with the highest TOSHI for the source category are respiratory and immunological.

[4] The maximum estimated acute exposure concentration was divided by available short-term threshold values to develop an array of hazard quotient (HQ) values. HQ values shown use the lowest available acute threshold value, which in most cases is the reference exposure level (REL). When an HQ exceeds 1, we also show the HQ using the next lowest available acute dose-response value.

BILLING CODE 6560–50–C

D. Summary of the 2020 Technology Review

Pursuant to CAA section 112(d)(6), the EPA conducted a technology review (2020 Technology Review) in the 2020 Final Action, which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since the 2012 MATS Final Rule was promulgated. Control technologies typically used to minimize emissions of pollutants that have numeric emission limits under the 2012 MATS Final Rule include electrostatic precipitators (ESPs) and fabric filters (FFs) for control of fPM as a surrogate for non-Hg HAP metals; wet scrubbers, dry scrubbers, and dry sorbent injection for control of acid gases (SO_2, HCl, and HF); and activated carbon injection (ACI) and other Hg-specific technologies for control of Hg. The EPA determined that the existing air pollution control technologies that were in use were well-established and provided the capture efficiencies necessary for compliance with the MATS emission limits. Based on the effectiveness and proven reliability of these control technologies, and the relatively short period of time since the promulgation of the 2012 MATS Final Rule, the EPA did not identify any developments in practices, processes, or control technologies, nor any new technologies or practices, for the control of non-Hg HAP metals, acid gas HAP, or Hg. However, in the 2020 Technology Review, the EPA did not consider developments in the cost and effectiveness of these proven technologies, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs, to determine whether revising the standards was warranted. Organic HAP, including emissions of dioxins and furans, are regulated by a work practice standard that requires periodic burner tune-ups to ensure good combustion. The EPA found that this work practice continued to be a practical approach to ensuring that combustion equipment was maintained and optimized to run to reduce emissions of organic HAP and continued to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. Based on the effectiveness and proven reliability of the work practice standard, and the relatively short amount of time since the promulgation of the 2012 MATS Final Rule, the EPA did not identify any developments in work practices nor any new work practices or operational procedures for this source category regarding the additional control of organic HAP.

After conducting the 2020 Technology Review, the EPA did not identify developments in practices, processes, or control technologies and, thus, did not propose changes to any emission standards or other requirements. More information concerning that technology review is in the memorandum titled Technology Review for the Coal- and Oil-Fired EGU Source Category, available in the docket (Document ID No. EPA–HQ–OAR–2018–0794–0015), and in the February 7, 2019, proposed rule. 84 FR 2700. On May 20, 2020, the EPA finalized the first technology review required by CAA section 112(d)(6) for the coal- and oil-fired EGU source category regulated under MATS. Based on the results of that technology review, the EPA found that no revisions to MATS were warranted. See 85 FR 31314 (May 22, 2020).

E. Summary of the EPA's Review of the 2020 RTR and the 2023 Proposed Revisions to the NESHAP

Pursuant to CAA section 112(d)(6), the EPA conducted a review of the 2020 Technology Review and presented the results of this review, along with our proposed decisions, in the 2023 Proposal. The results of the technology review are presented briefly below in this preamble. More detail on the proposed technology review is in the memorandum *2023 Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2023 Technical Memo'') (Document ID No. EPA–HQ–OAR–2018–0794–5789).

Based on the results of the technology review, the EPA proposed to lower the fPM standard, the surrogate for non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The Agency solicited comment on the control technology effectiveness and cost assumptions used in the proposed rule, as well as on a more stringent fPM limit of 0.006 lb/MMBtu or lower. Additionally, the Agency proposed to require the use of PM CEMS for all coal-fired, oil-fired, and IGCC EGUs for demonstrating compliance with the fPM standard. As the Agency proposed to require PM CEMS for compliance demonstration, we also proposed to remove the LEE option, a program based on infrequent stack testing, for fPM and non-Hg HAP metals. As EGUs would be required to demonstrate compliance with PM CEMS, the Agency also proposed to remove the alternate emission standards for non-Hg HAP metals and total HAP metals, because almost all regulated sources have chosen to demonstrate compliance with the non-Hg HAP metal standards by demonstrating compliance with the surrogate fPM standard, and solicited comment on prorated metal limits (adjusted proportionally according to the level of the final fPM standard), should the Agency not finalize the removal of the non-Hg HAP metals limits.

The Agency also proposed to lower the Hg emission standard for lignite-fired EGUs from 4.0 lb/TBtu to 1.2 lb/TBtu and solicited comment on the performance of Hg controls and on cost and effectiveness of control strategies to meet more stringent Hg standards. Lastly, the EPA did not identify new developments in control technologies or improved methods of operation that would warrant revisions to the Hg emission standards for non-lignite EGUs, for the organic HAP work practice standards, for the acid gas standards, or for standards for oil-fired EGUs. Therefore, the Agency did not propose changes to these standards in the 2023 Proposal but did solicit comment on the EPA's proposed findings that no revisions were warranted and on the appropriateness of the existing standards.

Additionally, the EPA proposed to remove one of the two options for defining the startup period for MATS-affected EGUs.

In the 2023 Proposal, the EPA determined not to reopen the 2020 Residual Risk Review, and accordingly did not propose any revisions to that review. As the EPA explained in the proposal, the EPA found in the 2020 RTR that risks from the Coal- and Oil-Fired EGU source category due to emissions of air toxics are acceptable and that the existing NESHAP provides an ample margin of safety to protect public health. As noted in the proposal, the EPA also acknowledges that it received a petition for reconsideration from environmental organizations that, in relevant part, sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review. The EPA granted in part the environmental organizations' petition which sought the EPA's review of startup and shutdown provisions in the 2023 Proposal, 88 FR 24885, and the EPA continues to review and will respond to other aspects of the petition in a separate action.[10]

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Coal- and Oil-Fired EGU source category and amends the Coal- and Oil-Fired EGU NESHAP based on those determinations. This action also finalizes changes to the definition of startup for this rule. This final rule includes changes to the 2023 Proposal after consideration of comments received during the public comment period described in sections IV., V., VI., and VII. of this preamble.

A. What are the final rule amendments based on the technology review for the Coal- and Oil-Fired EGU source category?

We determined that there are developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the MACT standards by revising the fPM limit for existing coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu and requiring the use of PM CEMS for coal and oil-fired EGUs to demonstrate compliance with the revised fPM standard, as proposed. We are also finalizing, as proposed, a Hg limit for lignite-fired EGUs of 1.2 lb/TBtu, which aligns with the existing Hg limit that has been in effect for other coal-fired EGUs since 2012. This revised Hg limit for lignite-fired EGUs is more stringent than the limit of 4.0 lb/TBtu that was finalized for such units in the 2012 MATS Final Rule. The rationale for these changes is discussed in more detail in sections IV. and V. below.

Based on comments received during the public comment period, the EPA is not finalizing the proposed removal of the non-Hg HAP metals limits for existing coal-fired EGUs (see section V.). Additionally, this final rule is requiring the use of PM CEMS for compliance demonstration for coal- and oil-fired EGUs (excluding EGUs in the limited-use liquid oil-fired subcategory), but not for IGCC EGUs (see section VI.).

Because this final rule includes revisions to the emissions standards for fPM as a surrogate for non-Hg HAP metals for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, the Hg emission standard for lignite-fired EGUs, and the definition of ''startup,'' the EPA intends each portion of this rule to be severable from each other as it is multifaceted and addresses several distinct aspects of MATS for independent reasons. This includes the revised emission standard for fPM as a surrogate for non-Hg HAP metals and the fPM compliance demonstration requirement to utilize PM CEMS. While the EPA considered the technical feasibility of PM CEMS in establishing the revised fPM standard, the EPA finds there are independent reasons for adopting each revision to the standards, and that each would continue to be workable without the other in the place.

[10] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov.*

The EPA intends that the various pieces of this package be considered independent of each other. For example, the EPA notes that our judgments regarding developments in fPM control technology for the revised fPM standard as a surrogate for non-Hg HAP metals largely reflect that the fleet was reporting fPM emission rates well below the current standard and with lower costs than estimated during promulgation of the 2012 MATS Final Rule; while our judgments regarding the ability for lignite-fired EGUs to meet the same standard for Hg emissions as other coal- and oil-fired EGUs rest on a separate analysis specific to lignite-fired units. Thus, the revised fPM surrogate emissions standard is feasible and appropriate even absent the revised Hg standard for lignite-fired units, and vice versa. Similarly, the EPA is finalizing changes to the fPM compliance demonstration requirement based on the technology's ability to provide increased transparency for owners and operators, regulators, and the public; and the EPA is finalizing changes to the startup definition based on considerations raised by environmental groups in petitions for reconsideration. Both of these actions are independent from the EPA's revisions to the fPM surrogate standard, and the Hg standard for lignite-fired units. Accordingly, the EPA finds that each set of standards is severable from each other set of standards.

Finally, the EPA finds that implementation of each set of standards, compliance demonstration requirements, and revisions to the startup definition are independent. That is, a source can abide by any one of these individual requirements without abiding by any others. Thus, the EPA's overall approach to this source category continues to be fully implementable even in the absence of any one or more of the elements included in this final rule.

Thus, the EPA has independently considered and adopted each portion of this final rule (including the revised fPM emission standard as a surrogate for non-Hg HAP metals, the fPM compliance demonstration requirement, the revised Hg emission standard for lignite-fired units, and the revised startup definition) and each is severable should there be judicial review. If a court were to invalidate any one of these elements of the final rule, the EPA intends the remainder of this action to remain effective. Importantly, the EPA designed the different elements of this final rule to function sensibly and independently. Further, the supporting bases for each element of the final rule reflect the Agency's judgment that the element is independently justified and appropriate, and that each element can function independently even if one or more other parts of the rule has been set aside.

B. What other changes have been made to the NESHAP?

The EPA is finalizing, as proposed, the removal of the work practice standards of paragraph (2) of the definition of "startup" in 40 CFR 63.10042. Under the first option, startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Under the second option, startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. The final rule requires that all EGUs use the work practice standards in paragraph (1) of the definition of "startup," which is already being used by the majority of EGUs.

C. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on July 8, 2024. The compliance date for affected coal-fired sources to comply with the revised fPM limit of 0.010 lb/MMBtu and for lignite-fired sources to meet the lower Hg limit of 1.2 lb/TBtu is 3 years after the effective date of the final rule. The Agency believes this timeline is as expeditious as practicable considering the potential need for some sources to upgrade or replace pollution controls. As discussed elsewhere in this preamble, we are adding a requirement that compliance with the fPM limit be demonstrated using PM CEMS. Based on comments received during the comment period and our understanding of suppliers of PM CEMS, the EPA is finalizing the requirement that affected sources use PM CEMS for compliance demonstration by 3 years after the effective date of the final rule. The compliance date for existing affected sources to comply with amendments pertaining to the startup definition is 180 days after the effective date of the final rule, as few EGUs are affected, and changes needed to comply with paragraph (1) of startup are achievable by all EGUs at little to no additional expenditures. All affected facilities remain subject to the current requirements of 40 CFR part 63, subpart UUUUU, until the applicable compliance date of the amended rule.

The EPA has considered the concerns raised by commenters that these compliance deadlines could affect electric reliability and concluded that given the flexibilities detailed further in this section, the requirements of the final rule for existing sources can be met without adversely impacting electric reliability. In particular, the EPA notes the flexibility of permitting authorities to allow, if warranted, a fourth year for compliance under CAA section 112(i)(3)(B). This flexibility, if needed, would address many of the concerns that commenters raised. Furthermore, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides additional flexibilities to bring sources into compliance while maintaining reliability.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision. In the 2012 MATS Final Rule, the EPA emphasized that most units should be able to comply with the requirements of the final rule within 3 years. However, the EPA also made it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in a range of situations described in the 2012 MATS Final Rule preamble.[11] The EPA's Office of Enforcement and Compliance Assurance (OECA) also issued the MATS Enforcement Response policy (Dec. 16, 2011)[12] which described the approach regarding the issue of CAA section 113(a) administrative orders with respect to the sources that must operate in noncompliance with the MATS rule for up to 1 year to address specific documented reliability concerns. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection with the Enforcement Response policy. The 2012 MATS Final Rule was ultimately implemented over the 2015—2016 timeframe without challenges to grid reliability.

[11] 77 FR 9406.

[12] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

IV. What is the rationale for our final decisions and amendments to the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance options from the 2020 Technology Review?

In this section, the EPA provides descriptions of what we proposed, what we are finalizing, our rationale for the final decisions and amendments, and a summary of key comments and responses related to the emission standard for fPM, non-Hg HAP metals, and the compliance demonstration options. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the comment summary and response document *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* available in the docket.

Based on its review, the EPA is finalizing a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu and is requiring that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. The revised fPM standard will ensure that the entire fleet of coal-fired EGUs achieves performance levels that are consistent with those of the vast majority of regulated units operating today—*i.e.,* that the small minority of units that currently emit significantly higher levels of HAP than their peers use proven technologies to reduce their HAP to the levels achieved by the rest of the fleet. Further, the EPA finds that a 0.010 lb/MMBtu fPM emission standard is the lowest level currently compatible with PM CEMS for demonstrating compliance, which the EPA finds provides significant benefits including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. In addition, the rule's current requirement to shift electronic reporting of PM CEMS data to the Emissions Collection and Monitoring Plan System (ECMPS) will enable regulatory authorities, nearby citizens, and others, including members of the public and media, to quickly and easily locate, review, and download fPM emissions using simple, user-directed inquiries. An enhanced, web-based version of ECMPS (ECMPS 2.0) is currently being prepared that will ease data editing, importing, and exporting and is expected to be available prior to the date by which EGUs are required to use PM CEMS.

A. What did we propose pursuant to CAA section 112(d)(6) for the Coal- and Oil-Fired EGU source category?

1. Proposed Changes to the Filterable PM Standard

The EPA proposed to lower the fPM limit, a surrogate for total non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The EPA further solicited comment on an emission standard of 0.006 lb/MMBtu or lower. The EPA did not propose any changes to the fPM emission standard for oil-fired EGUs or for IGCC units. The EPA also proposed to remove the total and individual non-Hg HAP metals emission limits. The EPA also solicited comment on adjusting the total and individual non-Hg HAP metals emission limits proportionally to the revised fPM limit rather than eliminating the limits altogether.

2. Proposed Changes to the Requirements for Compliance Demonstration

The EPA proposed to require that all coal- and oil-fired EGUs (IGCC units are discussed in section VI.) use PM CEMS to demonstrate compliance with the fPM emission limit. The EPA also proposed to remove the option of demonstrating compliance using infrequent stack testing and the LEE program (where stack testing occurs quarterly for 3 years, then every third year thereafter) for both PM and non-Hg HAP metals.

B. How did the technology review change for the Coal- and Oil-Fired EGU source category?

1. Filterable PM Emission Standard

Commenters provided both supportive and opposing arguments for issues regarding the fPM limit that were presented in the proposed review of the 2020 Technology Review. Comments received on the proposed fPM limit for coal-fired EGUs, along with additional analyses, did not change the Agency's conclusions that were presented in the 2023 Proposal, and, therefore, the Agency is finalizing the 0.010 lb/MMBtu fPM emission limit for existing coal-fired EGUs, as proposed.

Additionally, commenters urged the Agency to retain the option of complying with individual non-Hg HAP metal (*e.g.,* lead, arsenic, chromium, nickel, and cadmium) emission rates or with a total non-Hg HAP metal emission rate. After consideration of public comments, the Agency is finalizing updated limits for non-Hg HAP metals and total non-Hg HAP metals that have been reduced proportional to the reduction of the fPM emission limit from 0.030 lb/MMBtu to the new final fPM emission limit of 0.010 lb/MMBtu. EGU owners or operators who would choose to comply with the non-Hg HAP metals emission limits instead of the fPM limit must request and receive approval of a non-Hg HAP metal CMS as an alternative test method (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f).

2. Compliance Demonstration Options

Comments received on the compliance demonstration options for coal- and oil-fired EGUs also did not change the results of the technology review, therefore the Agency is finalizing the use of PM CEMS for compliance demonstration purposes and removing the fPM and non-Hg HAP metals LEE options for all coal-fired EGUs and for oil-fired EGUs (except those in the limited use liquid oil-fired EGU subcategory). The Agency received comments that some PM CEMS that are currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience some difficulties should re-correlation be necessary at a lower fPM standard. Based on these comments and on additional review of PM CEMS test reports, as mentioned in sections IV.C.2. and IV.D.2., the Agency has made minor technical revisions to shift the basis of correlation testing from sampling a minimum volume per run to collecting a minimum mass or minimum sample volume per run and has adjusted the quality assurance (QA) criterion otherwise associated with the new emission limit. These changes will enable PM CEMS to be properly certified for use in demonstrating compliance with the lower fPM standard with a high degree of accuracy and reliability.

C. What key comments did we receive on the filterable PM and compliance options, and what are our responses?

1. Comments on the Filterable PM Emission Standard

Comment: Some commenters supported the proposed fPM limit of 0.010 lb/MMBtu as reasonable and achievable, noting that this limit is slightly greater than the fPM emission limit required for new and reconstructed units. Additionally, commenters stated CAA section 112 was intended to improve the performance of lagging industrial sources and that a standard that falls far behind what the vast majority of sources have already achieved, as the current standard does, is inadequate. Other commenters opposed the proposed fPM limit of 0.010 lb/MMBtu as too stringent. For instance, some commenters stated that the EPA did not provide adequate support for the proposed limit. Other commenters stated that the fact that the vast majority of units are achieving emission rates below the current limit does not constitute ''developments in practices, processes, and control technologies.''

Response: The EPA disagrees that the Agency has not adequately supported the proposed fPM limit. As described in the proposal preamble, the Agency conducted a review of the 2020 Technology Review pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since promulgation of the 2012 MATS Final Rule. Based on that review, the EPA found that a majority of sources were not only reporting fPM emissions significantly below the current emission limit, but also that the fleet achieved lower fPM rates at lower costs than the EPA estimated when it promulgated the 2012 MATS Final Rule. The EPA explains these findings in more detail in section IV.D.1. of this preamble and elsewhere in the record. Further, the EPA finds that there are technological developments and improvements in PM control technology, which also controls non-Hg HAP metals, since the 2012 MATS Final Rule that informed the 2023 Proposal and this action, as discussed further in section IV.D.1. below. For example, industry has implemented ''best practices'' for monitoring ESP operation more carefully, and more durable materials have been adopted for FFs since the 2012 MATS Final Rule. The EPA also finds that these are cognizable developments for purposes of CAA section 112(d)(6). As other commenters noted, in *National Association for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015), the D.C. Circuit found that the EPA ''permissibly identified and took into account cognizable developments'' based on the EPA's interpretation of the term as ''not only wholly new methods, but also technological improvements.'' Similarly, here the EPA identified a clear trend in control efficiency, costs, and technological improvements, which the EPA is accounting for in this action. Further, as discussed elsewhere in this section and in section IV.D.1. of this preamble, the EPA finds case law and substantial administrative precedent support the EPA's decision to update the fPM limit based upon these developments.

Comment: Many commenters recommended that the EPA add a compliance margin in its achievability assumptions. These commenters conveyed that most EGUs typically operate well below the limit to allow for a compliance margin in the event of an equipment malfunction or failure, which they encouraged the EPA to consider when setting new limits. These commenters claimed that with a proposed fPM limit of 0.010 lb/MMBtu, an appropriate design margin of 20 percent necessitates that control technologies must be able to achieve a limit of 0.008 lb/MMBtu or lower in practice. They also expressed concerns that the EPA did not take design margin into consideration in the cost analysis. They stated that by not including the need for a design margin, which the EPA has acknowledged the need for in at least two of the Agency's publications (*NESHAP Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired EGUs,* Document ID No. EPA–HQ–OAR–2009–0234–20223 and *PM CEMS Capabilities Summary for Performance Specification 11, NSPS, and MACT Rules,* Document ID No. EPA–HQ–OAR–2018–0794–5828), the EPA underpredicted the number of units that would require retrofits. These commenters stated that the combination of a very low fPM limit and having to account for the measurement uncertainty and correlation methodology of PM CEMS would likely necessitate an ''operational target limit'' of 50 percent of the applicable limit. Some commenters referenced the National Rural Electric Cooperative Association (NRECA) technical evaluation for the 2023 Proposal titled *Technical Comments on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.*[13] They said that, even using the EPA's unrealistic ''baseline fPM rates'' and the lowest possible compliance margin of 20 percent, the NRECA technical evaluation estimated that 37 units—almost twice as many as the EPA's estimate—would be required to take substantial action to comply with the proposed limit.

Response: The EPA agrees that most facility operators normally target an emission level below the emission limit by incorporating a compliance margin or margin of error in case of equipment malfunctions or failures. As the commenters noted, the Agency has previously recognized that some operators target an emission level 20 to 50 percent below the limit. However, no commenters provided data to suggest that ESPs or FF are unable to achieve a lower fPM limit. Furthermore, the Agency does not prescribe specifically how an EGU controls its emissions or how the unit operates. The choice to target a lower-level emission rate for a compliance margin is the sole decision of owners and operators. For facilities with more than one EGU in the same subcategory, owners or operators may find emissions averaging (40 CFR 63.10009), coupled with or without a compliance margin, could help the facility attain and maintain emission limits as an effective, low-cost approach. Additionally, no commenters provided data to indicate that every owner or operator aims to comply with the fPM limit with the same compliance margin. Because some operators might aim for a larger compliance margin than others, it would be difficult to select a particular assumption about compliance margin for the cost analysis. Every operator plans for compliance differently and the EPA cannot know every operator's plans for a compliance margin. Even if the EPA were to assume a 20 percent compliance margin in its evaluation of PM controls, the results of the analysis would not change the EPA's decision to adopt a lower fPM limit. Specifically, a 20 percent compliance margin assumption to a fPM limit of 0.010 lb/MMBtu would increase the number of affected EGUs from 33 to 53 (14.1 to 23.9 GW affected capacity) and the annual compliance costs from $87.2M to $147.7M. The number of EGUs that demonstrated an ability to meet the lower fPM limit, but do not do so on average and therefore would require O&M, would increase from 17 to 27 (including the compliance margin). Similarly, the number of ESP upgrades (previously 11) and bag upgrades (previously 3) would also increase (to 20 and 4, respectively). There would be no change in the number of new FF installs. Therefore, cost-effectiveness values for fPM and individual and total non-Hg HAP metals would only increase slightly. Moreover, the 30-boiler operating day averaging period using PM CEMS for compliance

[13] *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.* Cichanowicz, *et al.* June 19, 2023. Attachment A to Document ID No. EPA–HQ–OAR–2018–0794–5994.

demonstration provides flexibility for owners and operators to account for equipment malfunctions, operational variability, and other issues. Lastly, as described in the 2023 Proposal, and updated here, the vast majority of coal-fired EGUs are reporting fPM emissions well below the revised fPM limit. For instance, the median fPM rate of the 296 coal-fired EGUs assessed in the 2024 Technical Memo is 0.004 lb/MMBtu,[14] or 60 percent below the revised fPM limit of 0.010 lb/MMBtu. The median fPM rate of a quarter of the best performing sources (N=74) is 0.002 lb/MMBtu, about 80 percent below the revised fPM limit of 0.010 lb/MMBtu. Therefore, for these reasons, the EPA disagrees with commenters that a compliance margin needs to be considered in the cost analysis.

The updated PM analysis, detailed in the memorandum *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2024 Technical Memo'') available in the docket, estimates that the number of EGUs that will need to improve their fPM emission rate to achieve a 0.010 lb/MMBtu limit has increased from the 20 EGUs assumed in the 2023 Proposal to 33 EGUs, which is more consistent with the NRECA technical evaluation estimate of 37 EGUs. This increase is a result of updated methodology that utilizes both the lowest achieved fPM rate (*i.e.,* the lowest quarter's 99th percentile) and the average fPM rate across all quarterly data when assessing PM upgrade and costs assumptions for the evaluated limits. The Agency disagrees with the commenters, however, that the 37 EGUs in the NRECA technical evaluation would require ''substantial action to comply with the proposed standard.'' In the Agency's revised analysis, only 13 EGUs would require capital investments to meet a fPM limit of 0.010 lb/MMBtu. Of these, only two EGUs at one facility (Colstrip) currently without the most effective PM controls are projected to require installation of a FF, the costliest PM control upgrade option, to meet 0.010 lb/MMBtu. The remaining nine EGUs projected by the EPA to require capital investments are estimated to require various levels of ESP upgrades. The EPA estimates that more than half (20 EGUs) would be able to comply without any capital investments and would instead require improvements to their existing FF or ESP as they have already demonstrated the ability to meet the limit, but do not do so on average.

Comment: Some commenters stated that cost effectiveness is an important consideration in technology reviews under CAA section 112(d)(6) and acknowledged that the EPA undertook cost-effectiveness analyses for the three fPM standards on which the Agency sought comment. However, the commenters stated, the NRECA technical evaluation found meaningful errors in the EPA's cost analysis, including unreasonably low capital cost estimates for ESP rebuilds and a failure to consider the variability of fPM due to changes in operation or facility design, by not utilizing a compliance margin. They asserted that these errors resulted in sizeable cost-effectiveness underestimates that eroded the EPA's overall determination that the proposed fPM limit is cost-effective. These commenters also asserted that the EPA's rationale was arbitrary on its face because it reversed, without explanation, the EPA's prior acknowledgements that a cost-effectiveness analysis should account for the cost effectiveness of controls at each affected facility and not simply on an aggregate nationwide basis. They stated that facility-specific costs should factor into the EPA's assessment of what is ''necessary'' pursuant to the provisions of CAA section 112(d)(6) and CAA section 112(f)(2).

Some commenters asserted that, even using the EPA's cost-effectiveness figures, the proposed 0.010 lb/MMBtu limit is not cost-effective. These commenters stated that the EPA's proposal to revise the fPM standard to 0.010 lb/MMBtu based on a cost-effectiveness estimate of up to $14.7 million per ton of total non-Hg HAP metals removed (equivalent to $44,900 per ton of fPM removed) is inconsistent with the EPA's prior actions because the cost-effectiveness estimate is substantially higher than estimates the Agency has previously found to be not cost-effective. They further said that, in the past, the EPA has decided against revising fPM standards based on cost-effectiveness estimates substantially lower than the cost-effectiveness estimates here. They said that the EPA should follow these precedents and acknowledge that $12.2 to $14.7 million per ton of non-Hg HAP metals reduced is not cost-effective. They argued that the Agency should not finalize the proposed standard of 0.010 lb/MMBtu for that reason. Further, these commenters argued that the alternative, more stringent limit of 0.006 lb/MMBtu is even less cost-effective at $25.6 million per ton of non-Hg HAP metals reduced, so it should not be considered either.

The commenters provided the following examples of previous rulemakings where EPA found controls to not be cost-effective:

- In the Petroleum Refinery Sector technology review,[15] the EPA declined to revise the fPM emission limit for existing fluid catalytic cracking units after finding that it would cost $10 million per ton of total non-Hg HAP metals reduced (in that case, equivalent to $23,000 per ton of fPM reduced), which was not cost-effective.
- In the Iron Ore Processing technology review,[16] the EPA declined to revise the non-Hg HAP metals limit after finding that installing wet scrubbers would cost $16 million per ton of non-Hg HAP metals reduced, which was not cost-effective.
- In the Integrated Iron and Steel Manufacturing Facilities technology review,[17] the EPA declined to revise the non-Hg HAP metals limit after finding that upgrading all fume/flame suppressants at blast furnaces to baghouses would cost $7 million per ton of non-Hg HAP metals reduced, which was not cost-effective. The Agency made a similar finding for a proposed limit that would have cost $14,000 per ton of volatile HAP reduced.
- In the Portland Cement Manufacturing beyond-the-floor analysis,[18] the EPA declined to impose a more stringent non-Hg HAP metals limit because it resulted in ''significantly higher cost effectiveness for PM than EPA has accepted in other NESHAP.'' The EPA noted in that rulemaking that it had previously ''reject[ed] $48,501 per ton of PM as not cost-effective for PM,'' and noted prior EPA statements in a subsequent rulemaking providing that $268,000 per ton of HAP removed was a higher cost-effectiveness estimate than the EPA had accepted in other NESHAP rulemakings.

In contrast, other commenters focused on the EPA's estimated cost-effective estimates for fPM (which is a surrogate for non-Hg HAP metals) and argued that

[14] For the revised fPM analysis, the EPA uses two methods to assess the performance of the fleet: average and the 99th percentile of the lowest quarter of data. Values reported here use the average fPM rate for each EGU.

[15] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[16] *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 85 FR 45476, 45483 (July 28, 2020).

[17] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[18] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10021 (February 12, 2013).

those estimates were substantially lower than estimates that the EPA has considered to be cost-effective in other technology reviews. Therefore, these commenters concluded that the EPA should strengthen the limit to at least 0.010 lb/MMBtu. These commenters also pointed to a 2023 report by Andover Technology Partners [19] that found that the cost to comply with an emission limit of 0.006 lb/MMBtu on a fleetwide basis was significantly less than the costs estimated by the EPA. Andover Technology Partners attributed this difference ''to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu.'' These commenters stated that meeting the lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, and they urged the EPA to adopt this limit. They stated that although cost effectiveness is less relevant in the CAA section 112 context than for other CAA provisions, the $103,000 per ton of fPM and $209,000 per ton of filterable fine $PM_{2.5}$ estimates that the EPA calculated for the 0.006 lb/MMBtu limit were reasonable and comparable to past practice in technology reviews under CAA section 112(d)(6). They noted that the EPA has previously found a control measure that resulted in an inflation-adjusted cost of $185,000 per ton of $PM_{2.5}$ reduced to be cost-effective for the ferroalloys production source category [20] and proposed a limit for secondary lead smelting sources that cost an inflation-adjusted $114,000 per ton of fPM reduced.[21] They argued that, using the Andover Technology Partners cost estimates, the 0.006 lb/MMBtu limit has even better cost-effectiveness estimates at about $72,000 per ton of fPM reduced and $146,000 per ton of filterable $PM_{2.5}$ reduced. These commenters noted that the EPA also calculated cost effectiveness based on allowable emissions (*i.e.,* assuming emission reductions achieved if all evaluated EGUs emit at the maximum allowable amount of fPM, or 0.030 lb/MMBtu) at $1,610,000 per ton, showing that a limit of 0.006 lb/MMBtu allows far less pollution at low cost to the power sector. They concluded that all these metrics and approaches to considering costs show that a fPM limit of 0.006 lb/MMBtu would require cost-effective reductions and can be achieved at a reasonable cost that would not jeopardize the power sector's function.

Additionally, some commenters cited *Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981), and said the case supports the EPA's discretion to weigh cost, energy, and environmental impacts, recognizing the Agency's authority to take these factors into account ''in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.'' These commenters said that the EPA has the authority to require costs that are reasonable for the industry even if they are not reasonable for every facility. These commenters acknowledged that the EPA has discretion to consider cost effectiveness under CAA section 112(d)(2), citing *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014), but argued that the dollar-per-ton cost-effectiveness metric is less relevant under CAA section 112 than under other CAA provisions because the Agency is not charged with equitably distributing the costs of emission reductions through a uniform compliance strategy, as the EPA has done in its transport rules. The commenters concluded that the Agency should require maximum reductions of HAP emissions from each regulated source category and has no authority to balance cost effectiveness across industries.

Response: In this action, the EPA is acting under its authority in CAA section 112(d)(6) to ''review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards'' promulgated under CAA section 112. As the EPA explained in the 2023 Proposal, this technology review is separate and distinct from other standard-setting provisions under CAA section 112, such as establishing MACT floors, conducting the beyond-the-floor analysis, and reviewing residual risk.

Regarding the comments that the EPA underestimated costs to an extent that undermines the EPA's overall cost-effectiveness assumptions, the EPA disagrees that the Agency underestimated the typical costs of ESP rebuilds. The commenters provided cost examples from only two facilities to support their assertions regarding the costs of ESP rebuilds. The costs provided for one of those facilities, Labadie, were not the costs associated with an ESP rebuild, but instead were the costs associated with the full replacement of an ESP. The commenter stated that, ''Ameren retrofitted the entire ESP trains on two units in 2014/2015. On each of these units two of the three original existing ESPs had to be abandoned and one of the existing ESPs was retrofitted with new power supplies and flue gas flow modifications. A new state-of-the-art ESP was added to each unit to supplement the retrofitted ESPs.'' An ESP replacement is different from an ESP rebuild, and therefore the costs of an ESP replacement do not inform the costs of an ESP rebuild. The ESP rebuild cost provided for the other facility, Petersburg, was less than the EPA's final assumption regarding the typical cost of an ESP rebuild on a capacity-weighted average basis. Neither of these examples provided by the commenter demonstrate that the EPA underestimated costs. For these reasons, the EPA disagrees with these commenters. Additionally, the EPA disagrees with these commenters that the Agency must add a compliance margin in its cost assumptions. As described above, the Agency does not prescribe specifically how an EGU must be controlled or how it must be operated, and the choice of overcompliance is at the sole discretion of the owners and operators.

Generally, the EPA agrees with commenters that cost effectiveness, *i.e.,* the costs per unit of emissions reduction, is a metric that the EPA consistently considers, often alongside other cost metrics, in CAA section 112 rulemakings where it can consider costs, *e.g.,* beyond-the-floor analyses and technology reviews, and agrees with commenters who recognize that the Agency has discretion in how it considers statutory factors under CAA section 112(d)(6), including costs. *See e.g., Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013) (allowing that the EPA may consider costs in conducting technology reviews under CAA section 112(d)(6)); *see also Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA acknowledges that the cost-effectiveness values for these standards are higher than cost-effectiveness values that the EPA concluded were not cost-effective and weighed against implementing more stringent standards for some prior rules. The EPA disagrees, however, that there is any particular threshold that renders

[19] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[20] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37381 (June 30, 2015).

[21] *National Emission Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 76 FR 29032 (May 19, 2011).

a rule cost-effective or not.[22] The EPA's prior findings about cost effectiveness in other rules were specific to those rulemakings and the industries at issue in those rules. As commenters have pointed out, in considering cost effectiveness, the EPA will often consider what estimates it has deemed cost-effective in prior rulemakings. However, the EPA routinely views cost effectiveness in light of other factors, such as other relevant costs metrics (*e.g.,* total costs, annual costs, and costs compared to revenues), impacts to the regulated industry, and industry-specific dynamics to determine whether there are ''developments in practices, processes, and control technologies'' that warrant updates to emissions standards pursuant to CAA section 112(d)(6). Some commenters, pointing to prior CAA section 112 rulemakings where the EPA chose not to adopt more stringent controls, mischaracterized cost effectiveness as the sole criterion in those decisions. These commenters omitted any discussion of other relevant factors from those rulemakings that, in addition to cost effectiveness, counseled the EPA against adopting more stringent standards. For example, in the 2014 Ferroalloys rulemaking that commenters cited to, the EPA rejected a potential control option due to questions about technical feasibility and significant economic impacts the option would create for the industry, including potential facility closures that would impact significant portions of industry production.[23] In contrast here, the controls at issue are technically feasible (they are used at facilities throughout the country) and will not have significant effects on the industry. Indeed, the EPA does not project that the final revisions to MATS will result in incremental changes in operational coal-fired capacity.

Similarly, in the other rulemakings these commenters pointed to, where the EPA found similar cost-effectiveness values to those that the EPA identified for the revised fPM standard here, there are distinct aspects of those rulemakings and industries that distinguish those prior actions from this rulemaking. In the 2015 Petroleum Refineries rulemaking, the EPA considered the cost effectiveness of developments at only two facilities to decide whether to deploy a standard across the much wider industry.[24] Here in contrast, the EPA is basing updates to fPM standards for coal-fired EGUs on developments across the majority of the industry and the performance of the fleet as a whole, which has demonstrated the achievability of a more stringent standard. Additionally, there are inherent differences between the power sector and other industries that similarly distinguish prior actions from this rulemaking. For example, because of the size of the power sector (314 coal-fired EGUs at 157 facilities), and because this source category is one of the largest stationary source emitters of Hg, arsenic, and HCl and is one of the largest regulated stationary source emitters of total HAP,[25] even considering that this rule affects only a fraction of the sector, the estimated HAP reductions in this final rule (8.3 tpy) are higher than those in the prior rulemakings cited by the commenters (as are the estimated PM reductions (2,537 tpy) used as a surrogate for non-Hg HAP metals). In contrast, in the 2020 Integrated Iron and Steel Manufacturing rulemaking, the source category covered included only 11 facilities, and the estimated reductions the EPA considered would have removed 3 tpy of HAP and 120 tpy of PM.[26] Likewise, in the 2013 Portland Cement rulemaking, the EPA determined not to pursue more stringent controls for the sector after finding the standard would only result in 138 tpy of nationwide PM reductions and that there was a high cost for such modest reductions.[27] Here, the EPA estimates significantly greater HAP emission reductions, and fPM emission reductions that are orders of magnitude greater than both prior rulemakings.[28]

There are also unique attributes of the power sector that the EPA finds support the finalization of revised standards for fPM and non-Hg HAP metals despite the relatively high cost-effectiveness values of this rulemaking as compared to other CAA section 112 rulemakings. As the EPA has demonstrated throughout this record, there are hundreds of EGUs regulated under MATS with well-performing control equipment that are already reporting emission rates below the revised standards, whereas only a handful of facilities with largely outdated or underperforming controls are emitting significantly more than their peers. That means that the communities located near these handful of facilities may experience exposure to higher levels of toxic metal emissions than communities located near similarly sized well-controlled plants. This is what the revised standards seek to remedy, and as discussed throughout this record, this goal is consistent with the EPA's authority under CAA section 112(d)(6) and the purpose of CAA section 112 more generally.

U.S. EGUs are a major source of HAP metals emissions including arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, manganese, and selenium. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). The emissions reductions projected under this final rule from the use of PM controls are expected to reduce exposure of individuals residing near these facilities to non-Hg HAP metals, including carcinogenic HAP.

EGUs projected to be impacted by the revised fPM standards represent a small fraction of the total number of the coal-fired EGUs (11 percent for the 0.010 lb/MMBtu fPM limit). In addition, many regulated facilities are electing to retire

[22] See *e.g., National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (''[I]t is important to note that there is no bright line for determining acceptable cost effectiveness for HAP metals. Each rulemaking is different and various factors must be considered.'').

[23] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 79 FR 60238, 60273 (October 6, 2014).

[24] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[25] 2020 National Emissions Inventory (NEI) Data; *https://www.epa.gov/air-emissions-inventories/2020-national-emissions-inventory-nei-data.*

[26] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[27] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10020–10021 (February 12, 2013).

[28] In addition, while commenters are correct that the EPA determined not to adopt more stringent controls under the iron ore processing technology review, the aspects of the rulemaking that the commenters cite to concerned whether additional controls were necessary to provide an ample margin of safety under a residual risk review. In that instance, the EPA determined not to implement more stringent standards under the risk review based on the installation of wet ESPs in addition to wet scrubbers, based on the EPA's determination that such improvements were not necessary to provide an ample margin of safety to protect public health. See *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 84 FR 45476, 45483 (July 28, 2020).

due to factors independent of the EPA's regulations, and the EPA typically has more information on plant retirements for this sector than other sectors regulated under CAA section 112. Both of these factors contribute to relatively higher cost-effectiveness estimates in this rulemaking as compared to other sectors where the EPA is not able to account for facility retirements and factor in shorter amortization periods for the price of controls.

While some commenters stated that meeting an even lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, the Agency declines to finalize this limit primarily due to the technological limitations of PM CEMS at this lower emission limit (as discussed in more detail in sections IV.C.2. and IV.D.2. below). Additionally, the EPA considered the higher costs associated with a more stringent standard as compared to the final standard presented in section IV.D.1.

Finally, as mentioned in the Response to Comments document, the EPA finds that use of PM CEMS, which provide continuous feedback with respect to fPM variability, in lieu of quarterly fPM emissions testing, will render moot the commenter's suggestion that margin of compliance has not been taken into account.

Comment: Some commenters argued that the low residual risks the EPA found in its review of the 2020 Residual Risk Review obviate the need for the EPA to revise the standards under the separate technology review, and that residual risk should be a relevant aspect of the EPA's technology review of coal- and oil-fired EGUs. These commenters argued that it is arbitrary and capricious for the EPA to impose high costs on facilities, which they claimed will only result in marginal emission reductions, when the EPA determined there is not an unreasonable risk to the environment or public health.

Other commenters agreed with the EPA's "two-pronged" interpretation that CAA section 112(d)(6) provides authorities to the EPA that are distinct from the EPA's risk-based authorities under CAA section 112(f)(2). These commenters said that if the criteria under CAA section 112(d)(6) are met, the EPA must update the standards to reflect new developments independent of the risk assessment process under CAA section 112(f)(2). They said the technology-based review conducted under CAA section 112(d)(6) need not account for any information learned during the residual risk review under CAA section 112(f)(2) unless that information pertains to statutory factors under CAA section 112(d)(6), such as costs. They concluded that CAA section 112(d)(6) requires the EPA to promulgate the maximum HAP reductions possible where achievable at reasonable cost and is separate from the EPA's residual risk analysis.

Response: The EPA has an independent statutory authority and obligation to conduct the technology review separate from the EPA's authority to conduct a residual risk review, and the Agency agrees with commenters that recognized that the EPA is not required to account for information obtained during a residual risk review in conducting a technology review. The EPA's finding that there is an ample margin of safety under the residual risk review in no way interferes with the EPA's obligation to require more stringent standards under the technology review where developments warrant such standards. The D.C. Circuit has recognized the CAA section 112(d)(6) technology review and 112(f)(2) residual review are "distinct, parallel analyses" that the EPA undertakes "[s]eparately." *Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 5 (D.C. Cir. 2015). In other recent residual risk and technology reviews, the EPA determined additional controls were warranted under technology reviews pursuant to CAA section 112(d)(6) although the Agency determined additional standards were not necessary to maintain an ample margin of safety under CAA section 112(f)(2).[29] The EPA has also made clear that the Agency "disagree[s] with the view that a determination under CAA section 112(f) of an ample margin of safety and no adverse environmental effects alone will, in all cases, cause us to determine that a revision is not necessary under CAA section 112(d)(6)." [30] While the EPA has considered risks as a factor in some previous technology reviews,[31] that does not compel the Agency to do so in this rulemaking. Indeed, in other instances, the EPA has adopted the same standards under both CAA sections 112(f)(2) and 112(d)(6) based on independent rationales where necessary to provide an ample margin of safety and because it is technically appropriate and necessary to do so, emphasizing the independent authority of the two statutory provisions.[32]

The language and structure of CAA section 112, along with its legislative history, further underscores the independent nature of these two provisions.[33] While the EPA is only required to undertake the risk review once (8 years after promulgation of the original MACT standards), it is required to undertake the technology review multiple times (at least every 8 years after promulgation of the original MACT standard). That Congress charged the EPA to ensure an ample margin of safety through the risk review, yet still required the technology review to be conducted on a periodic basis, demonstrates that Congress anticipated that the EPA would strengthen standards based on technological developments even after it had concluded there was an ample margin of safety. CAA section 112's overarching charge to the EPA to "require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions)" further demonstrates that Congress sought to minimize the emission of hazardous air pollution wherever feasible independent of a finding of risk. Moreover, as discussed *supra,* in enacting the 1990 CAA Amendments, Congress purposefully replaced the previous risk-based approach to establishing standards for HAP with a technology-driven approach. This technology-driven

[29] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Refractory Products Manufacturing Residual Risk and Technology Review,* 86 FR 66045 (November 19, 2021); *National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680 (July 10, 2020); *National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) Residual Risk and Technology Review,* 85 FR 40740, 40745 (July 7, 2020); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production,* 85 FR 40386, 40389 (July 6, 2020); *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills,* 82 FR 47328 (October 11, 2017); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards; and Manufacture of Amino/Phenolic Resins,* 79 FR 60898, 60901 (October 8, 2014).

[30] *National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry,* 76 FR 22566, 22577 (April 21, 2011).

[31] See, *e.g., National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry,* 71 FR 76603, 76606 (December 21, 2006); *see also Proposed Rules: National Emission Standards for Halogenated Solvent Cleaning,* 73 FR 62384, 62404 (October 20, 2008).

[32] *National Emissions Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012).

[33] See section II.A.2. above for further discussion of the statutory structure and legislative history of CAA section 112.

approach recognizes the ability for the EPA to achieve substantial reductions in HAP based on technological improvements without the inherent difficulty in quantifying risk associated with HAP emission exposure given the complexities of the pathways through which HAP cause harm and insufficient availability of data to quantify their effects discussed in section II.B.2. Independent of risks, it would be inconsistent with the text, structure, and legislative history for the EPA to conclude that Congress intended the statute's technology-based approach to be sidelined after the EPA had concluded the risk review.

Comment: Some commenters expressed concern that some portion of affected units could simply retire instead of coming into compliance with new requirements, potentially occurring before new generation could be built to replace the lost generation. During this period, a lack of dispatchable generation could significantly increase the likelihood of outages, particularly during periods of severe weather. In addition, some commenters argued that revising the fPM limit was unnecessary as there is a continuing downward trend in HAP emissions from early retirements of coal-fired EGUs, whereas accelerating this trend could have potential adverse effects on reliability. Some commenters also stated that as more capacity and generation is shifted away from coal-fired EGUs due to the Inflation Reduction Act (IRA) and other regulatory and economic factors, the total annual fPM and HAP emissions from industry will decline, regardless of whether the fPM limit is made more stringent.

Response: The EPA disagrees that this rule would threaten resource adequacy or otherwise degrade electric system reliability. Commenters provided no credible information supporting the argument that this final rule would result in a significant number of retirements or a larger amount of capacity needing controls. The Agency estimates that this rule will require additional fPM control at less than 12 GW of operable capacity in 2028, which is about 11 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM controls are projected to generate less than 1.5 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule. Because the EPA projects no incremental changes in existing operational capacity to occur in response to the final rule, the EPA does not anticipate this rule will have any implications for resource adequacy.

Nevertheless, it is possible that some EGU owners may conclude that retiring a particular EGU and replacing it with new capacity is a more economic option from the perspective of the unit's customers and/or owners than making investments in new emissions controls at the unit. The EPA understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some commenters nevertheless assume without any rationale that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service.

In addition, the Agency has granted the maximum time allowed for compliance under CAA section 112(i)(3) of 3 years, and individual facilities may seek, if warranted, an additional 1-year extension of the compliance date from their permitting authority pursuant to CAA section 112(i)(3)(B). The construction of any additional pollution control technology that EGUs might install for compliance with this rule can be completed within this time and will not require significant outages beyond what is regularly scheduled for typical maintenance. Facilities may also obtain, if warranted, an emergency order from the Department of Energy pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) that would allow the facility to temporarily operate notwithstanding environmental limits when the Secretary of Energy determines doing so is necessary to address a shortage of electric energy or other electric reliability emergency.

Further, despite the comments asserting concerns over electric system reliability, no commenter cited a single instance where implementation of an EPA program caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior CAA rulemakings have not been borne out in reality. For example, in the stay litigation over the Cross-State Air Pollution Rule (CSAPR), claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets. Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emission reduction targets years ahead of schedule without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) (''[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own . . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' '') (quoting 84 FR 32561). In other words, the claims that these rules would have had adverse reliability impacts proved to be groundless.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision.[34] As with the current rule, the flexibility of permitting authorities to allow a fourth year for compliance was available in a broad range of situations, and in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability. We have seen no evidence in the last decade to suggest

[34] The EPA projected that the 2012 MATS Final Rule would drive the installation of an additional 20 GW of dry FGD (dry scrubbers), 44 GW of DSI, 99 GW of additional ACI, 102 GW of additional FFs, 63 GW of scrubber upgrades, and 34 GW of ESP upgrades. While a subsequent analysis found that the industry ultimately installed fewer controls than was projected, the control installations that occurred following the promulgation of the 2012 MATS Final Rule were still significantly greater than the installations that are estimated to occur as a result of this final rule (where, for example, the EPA estimates that less than 2 GW of capacity would install FF technology for compliance).

that the implementation of MATS caused power sector adequacy and reliability problems, and only a handful of sources obtained administrative orders under the enforcement policy issued with MATS to provide relief to reliability critical units that could not comply with the rule by 2016.

Comment: Commenters suggested that the EPA use its authority to create subcategories of affected facilities that elect to permanently retire by the compliance date as the Agency has taken in similar proposed rulemakings affecting coal- and oil-fired EGUs. Commenters stated the EPA should subcategorize those sources that have adopted enforceable retirement dates and not subject those sources to any final rule requirements. They indicated that the EPA is fully authorized to subcategorize these units under CAA section 112(d)(1). Commenters asked that the EPA consider other simultaneous rulemakings, such as the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel Power Plants,[35] where the EPA proposed that EGUs that elect to shut down by January 1, 2032, must maintain their recent historical carbon dioxide (CO_2) emission rate via routine maintenance and operating procedures (*i.e.,* no degradation of performance). Commenters also referenced the retirement date of December 31, 2032, in the EPA Office of Water's proposed Effluent Limitation Guidelines.[36]

Commenters claimed that creating a subcategory for units facing near-term retirements that harmonizes the retirement dates with other rulemakings would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, forced to deliberate whether to install controls and delaying retirement to recoup investments in the controls. Commenters also suggested that EGUs with limited continued operation be allowed to continue to perform quarterly stack testing to demonstrate compliance with the fPM limitations (rather than having to install PM CEMS). Commenters suggested that imposing different standards on these subcategories should continue the status quo for these units until retirement. Commenters claimed that it would make no sense for the EPA to require an EGU slated to retire in the near term to expend substantial resources on controls in the interim since these sources are very unlikely to find it viable to construct significant control upgrades for a revised standard that would become effective in mid-2027, only 5 years before the unit's permanent retirement. Commenters further noted if the EPA does not establish such a subcategory or take other action to ensure these units are not negatively impacted by the rulemaking, the retirement of some units could be accelerated due to the costs of installing a PM CEMS and the need to rebuild or upgrade an existing ESP or install a FF to supplement an existing ESP. Commenters stated that the EPA cannot ignore the need for a coordinated retirement of thermal generating capacity while new generation sources come online to avoid detrimental impacts to grid reliability.

Commenters suggested that if the EPA decides to proceed with finalizing the revised standards in the 2023 Proposal, the Agency should create a subcategory for coal-fired EGUs that elect by the compliance date of the revised standards (*i.e.,* mid-2027) to retire the units by December 31, 2032, or January 1, 2032, if the EPA prefers to tie the 2023 Proposal to the proposed Emission Guidelines instead of the Effluent Limitation Guidelines, and maintain the current MATS standards for this subcategory of units. Commenters requested that the EPA coordinate the required retirement date for the 2023 Proposal with other rules so that all retirement dates align. Commenters reiterated that the EPA has multiple authorities with overlapping statutory timelines that affect commenters' plans regarding the orderly retirement of coal-fired EGUs and their ability to continue the industry's clean energy transformation while providing the reliability and affordability that their customers demand. Commenters suggested that EGUs that plan to retire by 2032 should have the opportunity to seek a waiver from PM CEMS installation altogether and continue quarterly stack testing during the remaining life of the unit. They also suggested that if a unit does not retire by the specified date, it should be required to immediately cease operation or meet the standards of the rule. Commenters stated that under this recommendation an EGU's failure to comply would then be a violation of the 2023 Proposal's final rule subject to enforcement.

Response: In response to commenters' concerns, the EPA evaluated the feasibility of creating a subcategory for facilities with near-term retirements but disagrees with commenters that such a subcategory is appropriate for this rulemaking. In particular, the EPA found that, based on its own assessment and that of commenters, only a few facilities would likely be eligible for a near-term retirement subcategory and that it would not significantly reduce the costs of the revised standards. According to the EPA's assessment, 67 of the 296 EGUs assessed[37] have announced retirements between 2029 and 2032—less than one-quarter of the fleet—and all but three of those EGUs (at two facilities) have already demonstrated the ability to comply with the 0.010 lb/MMBtu fPM standard on average. Additionally, these three EGUs already use PM CEMS to demonstrate compliance, therefore the comment requesting a waiver of PM CEMS installations for EGUs with near-term retirements is not relevant. Because the EPA's analysis led the Agency to conclude that there would be little utility to a near-term retirement subcategory and it would not change the costs of the rule in a meaningful way, the EPA determined not to create a retirement subcategory for the fPM standard. In addition, the EPA notes that allowing units to operate without the best performing controls for an additional number of years would lead to higher levels of non-Hg HAP metals emissions and continued exposure to those emissions in the communities around these units during that timeframe. Regarding a fPM compliance requirement subcategory for EGUs with near-term retirements, the Agency estimates 26 of 67 EGUs are already using PM CEMS for compliance demonstration and finds that the costs to install PM CEMS for facilities with near-term retirements are reasonable. The Agency finds that the transparency provided by PM CEMS and the increased ability to quickly detect and correct potential control or operational problems using PM CEMS furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring for all EGUs.

2. Comments on the Proposed Changes to the Compliance Demonstration Options

Comment: The Agency received both supportive and opposing comments requiring the use of PM CEMS for compliance demonstration. Supportive commenters stated the EPA must require the use of PM CEMS to monitor their emissions of non-Hg HAP metals

[35] 88 FR 33245 (May 23, 2023).

[36] 88 FR 18824, 18837 (March 29, 2023).

[37] In this final rule, the EPA reviewed fPM compliance data for 296 coal-fired EGUs expected to be operational on January 1, 2029. This review is explained in detail in the 2024 Technical Memo.

as PM CEMS are now more widely deployed than when MATS was first promulgated, and experience with PM CEMS has enabled operators to more promptly detect and correct problems with pollution controls as compared to other monitoring and testing options allowed under MATS (*i.e.,* periodic stack testing and parametric monitoring for PM), thereby lowering HAP emissions. They said that the fact that PM CEMS have been used to demonstrate compliance in a majority of units in the eight best performing deciles [38] provides strong evidence that PM CEMS can be used effectively to measure low levels of PM emissions.

Opposing commenters urged the EPA to retain all current options for demonstrating compliance with non-Hg HAP metal standards, including quarterly PM and metals testing, LEE, and PM CPMS. These commenters said removing these compliance flexibility options goes beyond the scope of the RTR and does not address why the reasons these options were originally included in MATS are no longer valid. Commenters said they have previously raised concerns about PM CEMS that the EPA has avoided by stating that CEMS are not the only compliance method for PM. They stated that previously, the EPA has determined these compliance methods were both adequate and frequent enough to demonstrate compliance.

Response: The Agency disagrees with commenters who suggests that the rule should retain all previous options for demonstrating compliance with either the individual metals, total metals, or fPM limits. Congress intended for CAA section 112 to achieve significant reductions of HAP, and the EPA agrees with other commenters that the use of CEMS in general and PM CEMS in particular enables owners or operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Consistent with the discussion contained in the 2023 Proposal (88 FR 24872), the Agency finds the transparency and ability to quickly detect and correct potential control or operational problems furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring.

Comment: Some commenters objected to the EPA's proposal to require the use of PM CEMS for purposes of demonstrating compliance with the revised fPM standard, stating that the requirements of Performance Specification 11 of 40 CFR part 60, appendix B (PS–11) will become extremely hard to satisfy at the low emission limits proposed. For PS–11, relative correlation audit (RCA), and relative response audit (RRA), the tolerance interval and confidence interval requirements are expressed in terms of the emission standard that applies to the source. The commenters reviewed test data from operating units and found significantly higher PS–11 failure (>80 percent), RCA failure (>80 percent), and RRA failure (60 percent) rates at the more stringent proposed emission limits. They stated that the cost, complexity, and failure rate of equipment calibration remains one of the biggest challenges with the use of PM CEMS and therefore other compliance demonstration methods should be retained. Commenters also noted that repeated tests due to failure could result in higher total emissions from the units.

Response: The Agency is aware of concerns by some commenters that PM CEMS currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience difficulties should re-correlation be necessary; and those concerns are also ascribed to yet-to-be installed PM CEMS. In response to those concerns, the Agency has shifted the basis of correlation testing from requiring only the collection of a minimum volume per run to also allowing the collection of a minimum mass per run and has adjusted the QA criterion otherwise associated with the new emission limit. These changes will ease the transition for coal- and oil-fired EGUs using only PM CEMS for compliance demonstration purposes. The first change, allowing the facility to choose either the collection of a minimum mass per run or a minimum volume per run, should reduce high-level correlation testing duration, addressing other concerns about extended runtimes with degraded emissions control or increased emissions, and should reduce correlation testing costs. The second change, adjusting the QA criteria, is consistent with other approaches the Agency has used when lower ranges of instrumentation or methods are employed. For example, in section 13.2 of Performance Specification 2 (40 CFR part 60, appendix B) the QA criteria for the relative accuracy test audit for SO_2 and Nitrogen Oxide CEMS are relaxed as the emission limit decreases. This is accomplished at lower emissions by allowing a larger criterion or by modifying the calculation and allowing a less stringent number in the denominator. With these changes to the QA criteria and correlation procedures, the EPA believes EGUs will be able to use PM CEMS to demonstrate compliance at the revised level of the fPM standard.

Comment: Some commenters asserted that if the EPA finalizes the requirement to demonstrate compliance using PM CEMS, EGUs will not be able to comply with a lower fPM limit on a continuous basis and that accompanying a lower limit with more restrictive monitoring requirements adds to the regulatory burden of affected sources and permitting authorities.

Response: The EPA disagrees with commenters' claim that that EGUs will not be able to demonstrate compliance continuously with a fPM limit of 0.010 lb/MMBtu. The EPA believes that CEMS in general and PM CEMS in particular enable owners and operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Contrary to the commenter's assertion that EGUs will not be able to comply with a lower fPM limit on a continuous basis, as mentioned in the June 2023 Andover Technology Partners analysis,[39] over 80 percent of EGUs using PM CEMS for compliance purposes have already been able to achieve and are reporting and certifying consistent achievement of fPM rates below 0.010 lb/MMBtu.[40] The EPA is unaware of any additional burden experienced by those EGU owners or operators or their regulatory authorities with regard to PM CEMS use at these lower emission levels, and does not expect additional burden to be placed on EGU owners or operators with regard to PM CEMS from application of the revised emission limit. However, this final rule incorporates approaches, such as switching from a minimum sample volume per run to collection of a

[38] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[39] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. June 2023. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[40] See for example the PM CEMS Thirty Boiler Operating Day Rolling Average Reports for Duke's Roxboro Steam Electric Plant in North Carolina and at Minnesota Power's Boswell Energy Center in Minnesota. These reports and those from other EGUs reporting emission levels at or lower than 0.010 lb/MMBtu are available electronically by searching in the EPA's Web Factor Information Retrieval System (WebFIRE) Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

minimum mass sample or mass volume per run and adjusting the PM CEMS QA acceptability criteria, to reduce the challenges with using PM CEMS. Moreover, the 30-boiler-operating-day averaging period of the limit provides flexibility for owners and operators to account for equipment malfunctions and other issues. Consistent with the discussion in the 2023 Proposal,[41] the Agency finds that PM CEMS are the best choice for this rule's compliance monitoring as they provide increased emissions transparency, ability for EGU owner/operators to quickly detect and correct potential control or operational problems, and greater assurance of continuous compliance. While PM CEMS can produce values at lower levels provided correlations are developed appropriately, the Agency established the final fPM limit of 0.010 lb/MMBtu after considering factors such as run times necessary to develop correlations, potential random error effects, and costs.

Comment: Commenters stated that the EPA's cost estimates contradict the Agency's suggestion that the use of PM CEMS is a more cost-effective monitoring approach than quarterly testing, especially for units that qualify as LEE. They said that the EPA used estimates from the Institute of Clean Air Companies (ICAC) or Envea/Altech which do not include numerous costs associated with PM CEMS that make them not cost-effective, such as the cost of intermittent stack testing associated with the PS–11 correlations and the ongoing costs of RCAs and RRA, which are a large part of the costs associated with PM CEMS and would rise substantially in conjunction with the proposed new PM limits. The commenters said that the ICAC estimated range of PM CEMS installation costs are particularly understated and outdated and should be ignored by the Agency. They said that the EPA estimates may also understate PM CEMS cost by assuming the most commonly used light scattering based PM CEMS will be used for all applications. The commenters said that while more expensive, a significant number of beta gauge PM CEMS are used for MATS compliance, especially where PM spiking is used for PS–11 correlation and RCA testing and that this higher degree of accuracy from beta gauge PM CEMS may be needed for sources without a margin of compliance under the new, more stringent emission limit.

Response: The EPA disagrees with the commenters' suggestion that the Agency is required to select the most cost-effective approach for compliance monitoring. Rather, the Agency selects the approach that best provides assurance that emission limits are met. PM CEMS annual costs represent a very small fraction of a typical coal-fired EGU's operating costs and revenues. As described in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, available in the docket, if all coal-fired EGUs were to purchase and install new PM CEMS, the Equivalent Uniform Annual Cost (EUAC) would represent less than four hundredths of a percent of the average annual operating expenses from coal-fired EGUs.

Further, as described in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* technical memorandum, available in the rulemaking docket, the EPA calculated average costs for PM CEMS and quarterly testing from values submitted by commenters in response to the proposal's solicitation, which are discussed in section IV.D. of the preamble. Based on the commenters' suggestions, these revised costs include the costs of intermittent stack testing associated with the PS–11 correlations and ongoing costs of RCAs and RRAs. While the average EUAC for PM CEMS exceeds the average annual cost of quarterly stack emission testing, the cost for PM CEMS does not include important additional benefits associated with providing continuous emissions data to EGU owners or operators, regulators, nearby community members, or the general public. As a reminder, the EPA is not obligated to choose the most inexpensive approach for compliance demonstrations, particularly when all benefits are not monetized, even though costs can be an important consideration. Consistent with the discussion contained in the 2023 Proposal at 88 FR 24872, the Agency finds the increased transparency of EGU fPM emissions and the ability to quickly detect and correct potential control or operational problems, along with greater assurance of continuous compliance makes PM CEMS the best choice for this rule's compliance monitoring.

The Agency acknowledges the commenters' suggestions that EGU owners or operators may find that using beta gauge PM CEMS is most appropriate for the lower fPM emission limit in the rule; such suggestions are consistent with the Agency's view, as expressed in 88 FR 24872. However, the Agency believes other approaches, including spiking, can also ease correlation testing for PM CEMS. Moreover, the Agency anticipates that the new fPM limit will increase demand for, and perhaps spur increased production of, beta gauge PM CEMS.

D. What is the rationale for our final approach and decisions for the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance demonstration options?

The EPA is finalizing a lower fPM emission standard of 0.010 lb/MMBtu for coal-fired EGUs, as a surrogate for non-Hg HAP metals, and the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs (with the exception of limited-use liquid oil-fired EGUs) based on developments in the performance of sources within the category since the EPA finalized MATS and the advantages conferred by using CEMS for compliance. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in concomitant reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2). The EPA observes that since MATS was finalized, the vast majority of covered units have significantly outperformed the standard, with a small number of units lagging behind and emitting significantly higher levels of these HAP in communities surrounding those units. The EPA deems it appropriate to require these lagging units to bring their pollutant control performance up to that of their peers. Moreover, the EPA concludes that requiring use of PM CEMS for compliance yields manifold benefits, including increased emissions transparency and data availability for owners and operators and for nearby communities.

The EPA's conclusions with regard to the fPM standard and requirement to use PM CEMS for compliance demonstration are closely related, both in terms of CAA section 112(d)(6)'s direction for the EPA to reduce HAP emissions based on developments in practices, processes, and control technologies, and in terms of technical compatibility.[42] The EPA finds that the manifold benefits of PM CEMS render it appropriate to promulgate an updated fPM emission standard as a surrogate for non-Hg HAP metals for which PM CEMS can be used to monitor

[41] See 88 FR 24872.

[42] As noted in section III.A. above, there are nonetheless independent reasons for adopting both the revision to the fPM standard and the PM CEMS compliance demonstration requirement and each of these changes would continue to be workable without the other in effect, such that the EPA finds the two revisions are severable from each other.

compliance. However, as the fPM limit is lowered, operators may encounter difficulties establishing and maintaining existing correlations for the PM CEMS and may therefore be unable to provide accurate values necessary for compliance. The EPA has determined, based on comments and on the additional analysis described below, that the lowest possible fPM limit considering these challenges at this time is 0.010 lb/MMBtu with adjusted QA criteria. Therefore, the EPA determined that this two-pronged approach—requiring PM CEMS in addition to a lower fPM limit—is the most stringent option that balances the benefits of using PM CEMS with the emission reductions associated with the tightened fPM emission standard. Further, the EPA finds that the more stringent limit of 0.006 lb/MMBtu fPM cannot be adequately monitored with PM CEMS at this time, because the random error component of measurement uncertainty from correlation stack testing is too large and the QA criteria passing rate for PM CEMS is too small to provide accurate (and therefore enforceable) compliance values. Below, we further describe our rationale for each change.

1. Rationale for the Final Filterable PM Emission Standard

In the 2023 Proposal, the Agency proposed a lower fPM emission standard for coal-fired EGUs as a surrogate for non-Hg HAP metals based on developments in practices, processes, and control technologies pursuant to CAA section 112(d)(6), including the EPA's assessment of the differing performance of sources within the category and updated information about the cost of controls. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2).

In conducting this technology review, the EPA found important developments that informed its proposal. First, from reviewing historical information contained in WebFIRE,[43] the EPA observed that most EGUs were reporting fPM emission rates well below the 0.030 lb/MMBtu standard. The fleet was achieving these performance levels at lower costs than estimated during promulgation of the 2012 MATS Final Rule. Second, there are technical developments and improvements in PM control technology since the 2012 MATS Final Rule that informed the 2023 Proposal.[44] For example, while ESP technology has not undergone fundamental changes since 2011, industry has learned and adopted "best practices" associated with monitoring ESP operation more carefully since the 2012 MATS Final Rule. For FFs, more durable materials have been developed since the 2012 MATS Final Rule, which are less likely to fail due to chemical, thermal, or abrasion failure and create risks of high PM emissions. For instance, fiberglass (once the most widely used material) has largely been replaced by more reliable and easier to clean materials, which are more costly. Coated fabrics, such as Teflon or P84 felt, also clean easier than other fabrics, which can result in less frequent cleaning, reducing the wear that could damage filter bags and reduce the effectiveness of PM capture.

To examine potential revisions, the EPA evaluated fPM compliance data for the coal-fired fleet and evaluated the control efficiency and costs of PM controls to achieve a lower fPM standard. Based on comments received on the 2023 Proposal, the EPA reviewed additional fPM compliance data for 62 EGUs at 33 facilities (see 2024 Technical Memo and attachments for detailed information). The review of additional fPM compliance data showed that more EGUs had previously demonstrated an ability to meet a lower fPM rate, as shown in figure 4 of the 2024 Technical Memo. Compared to the 2023 Proposal where 91 percent of existing capacity demonstrated an ability to meet 0.010 lb/MMBtu, the updated analysis showed that 93 percent are demonstrating the ability to meet 0.010 lb/MMBtu with existing controls. The EPA received comments on the cost assumptions for upgrading PM controls and found that the costs estimated at proposal were not only too high, but that the cost effectiveness of PM upgrades was also underestimated (*i.e.,* the standard is more cost-effective than the EPA believed at proposal).

The EPA is finalizing the fPM emission limit of 0.010 lb/MMBtu with adjusted QA criteria, based on developments since 2012, for the reasons described in this final rule and in the 2023 Proposal as the lowest achievable fPM limit that allows for the use of PM CEMS for compliance demonstration purposes. First, this level of control ensures that the highest emitters bring their performance to a level where the vast majority of the fleet is already performing. For example, as described above, the majority of the existing coal-fired fleet subject to this final rule has previously demonstrated an ability to comply with the lower 0.010 lb/MMBtu fPM limit at least 99 percent of the time during one quarter, in addition to meeting the lower fPM limit on average across all quarters assessed. The Agency estimates that only 33 EGUs are currently operating above this revised limit. Compared to some of the best performing EGUs, the 33 EGUs requiring additional PM control upgrades or maintenance are more likely to have an ESP instead of a FF and to demonstrate compliance using intermittent stack testing. In addition, most of these EGUs have operated at a higher level of utilization than the coal-fired fleet on average.

Second, as discussed in section II.A.2. above, Congress updated CAA section 112 in the 1990 Clean Air Act Amendments to achieve significant reductions in HAP emissions, which it recognized are particularly harmful pollutants, and implemented a regime under which Congress directed the EPA to make swift and substantial reductions to HAP based upon the most stringent standards technology could achieve. This is evidenced by Congress's charge to the EPA to "require the maximum degree of reduction in emissions of hazardous air pollutants (including a prohibition on such emissions)," that is achievable accounting for "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements. . . ." CAA section 112(d)(2). Further, by creating separate and distinct requirements for the EPA to consider updates to CAA section 112 pursuant to both technology review under CAA section 112(d)(6) and residual risk review under CAA section 112(f)(2), Congress anticipated that the EPA would strengthen standards pursuant to technology reviews "as necessary (taking into account developments in practices, processes, and control technologies)," CAA section 112(d)(6), even after the EPA concluded there was an ample margin of safety based on the risks that the EPA can quantify.[45] As the EPA explained in the

[43] WebFIRE includes data submitted to the EPA from the Electronic Reporting Tool (ERT) and is searchable at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[44] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[45] EPA's CAA section 112(f)(2) quantitative risk assessments evaluate cancer risk associated with a lifetime of exposure to HAP emissions from each source in the source category, the potential for HAP exposure to cause adverse chronic (or long-term) noncancer health effects, and the potential for HAP

proposal, the EPA does consider costs, technical feasibility, and other factors when evaluating whether it is necessary to revise existing emission standards under CAA section 112(d)(6) to ensure the standards ''require the maximum degree of emissions reductions . . . achievable.'' CAA section 112(d)(2). The text, structure, and history of this provision demonstrate Congress's direction to the EPA to require reduction in HAP where technology is available to do so and the EPA accounts for the other statutory factors.

Accordingly, the EPA finds that bringing this small number of units to the performance levels of the rest of the fleet serves Congress's mandate to the EPA in CAA section 112(d)(6) to continually consider developments ''that create opportunities to do even better.'' *See LEAN,* 955 F.3d at 1093. As such, the EPA has a number of times in the past updated its MACT standards to reflect developments where the majority of sources were already outperforming the original MACT standards.[46] Indeed, this final rule is consistent with the EPA's authority pursuant to CAA section 112(d)(6) to take developments in practices, processes, and control technologies into account to determine if more stringent standards are achievable than those initially set by the EPA in establishing MACT floors, based on developments that occurred in the interim. *See LEAN* v. *EPA,* 955 F.3d 1088, 1097–98 (D.C. Cir. 2020). The technological standard approach of CAA section 112 is based on the premise that, to the extent there are controls available to reduce HAP emissions, and those controls are of reasonable cost, sources should be required to use them.

The fleet has been able to ''over comply'' with the existing fPM standard due to the very high PM control effectiveness of well-performing ESPs and FFs, often exceeding 99.9 percent. But the performance of a minority of units lags well behind the vast majority of the fleet. As indicated by the two highest fPM rates,[47] EGUs without the most effective PM controls have not been able to demonstrate fPM rates comparable to the rest of the fleet. Specifically, the Colstrip facility, a 1,500 MW subbituminous-fired power plant located in Colstrip, Montana, operates the only two coal-fired EGUs in the country without the most modern PM controls (*i.e.,* ESP or FF). Instead, this facility utilizes venturi wet scrubbers as its primary PM control technology and has struggled to meet the original 0.030 lb/MMBtu fPM limit, even while employing emissions averaging across the operating EGUs at the facility. Colstrip is also the only facility where the EPA estimates the current controls would be unable to meet a lower fPM limit. Specifically, the 2018 second quarter compliance stack tests showed average fPM emission rates above the 0.030 lb/MMBtu fPM limit, in violation of its Air Permit. Talen Energy, one of the owners of the facility, agreed to pay $450,000 to settle these air quality violations.[48] As a result, the plant was offline for approximately 2.5 months while the plant's operator worked to correct the problem. Comments from Colstrip's majority owners discuss the efforts this facility has undergone to improve their wet PM scrubbers, which they state remove 99.7 percent of the fly ash particulate but agree with the EPA that additional controls would be needed to meet a 0.010 lb/MMBtu limit. However, as stated in *NorthWestern Energy's Annual PCCAM Filing and Application of Tariff Changes*,[49] ''Colstrip has a history of operating very close to the upper end limit: for 43 percent of the 651 days of compliance preceding the forced outage its [Weighted Average Emission Rate or] WAER was within 0.03 lb/dekatherm[50] of the limit [. . . to comply with the Air Permit and MATS, Colstrip's WAER must be equal to or less than 0.03 lb/dekatherm].''

The Northern Cheyenne Reservation is 20 miles from the Colstrip facility and the Tribe exercised its authority in 1977 to require additional air pollution controls on the new Colstrip units (Colstrip 3 and 4, the same EGUs still operating today), recognizing the area as a Class I airshed under the CAA. According to comments submitted by the Northern Cheyenne Tribe, their tribal members—both those living on the Reservation and those living in the nearby community of Colstrip—have been disproportionally impacted by exposure to HAP emissions from the Colstrip facility.[51]

The EPA believes a fPM emission limit of 0.010 lb/MMBtu appropriately takes into consideration the costs of controls. The EPA evaluated the costs to improve current PM control systems and the cost to install better performing PM controls (*i.e.,* a new FF) to achieve a more stringent emission limit. Costs of PM upgrades are much lower than the EPA estimated in 2012, and the Agency revised its costs assumptions as described in the 2024 Technical Memo, available in the docket. Table 4 of this document summarizes the updated cost effectiveness of the three fPM emission limits considered in the 2023 Proposal for the existing coal-fired fleet. For the purpose of estimating cost effectiveness, the analysis presented in this table, described in detail in the 2023 and 2024 Technical Memos, is based on the observed emission rates of all existing coal-fired EGUs except for those that have announced plans to retire by the end of 2028. The analysis presented in table 4 estimated the costs associated for each unit to upgrade their existing PM controls to meet a lower fPM standard. In the cases where existing PM controls would not achieve the necessary reductions, unit-specific FF install costs were estimated. Unlike the cost and benefit projections presented in the RIA, the estimates in this table do not account for any future changes in the composition of the operational coal-fired EGU fleet that are likely to occur by 2028 as a result of other factors affecting the power sector, such as the IRA, future regulatory actions, or changes in economic conditions. For example, of the more than 14 GW of coal-fired capacity that the EPA estimates would require control improvements to achieve the final fPM rate, less than 12 GW is projected to be

exposure to cause adverse acute (or short-term) noncancer health effects.

[46] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680, 41698 (July 10, 2020) (proposed 84 FR 46138, 46161; September 3, 2019)) (requiring compliance with more stringent equipment leak definitions under a technology review, which were widely adopted by industry); *National Emissions Standards for Mineral Wool Production and Fiberglass Manufacturing,* 80 FR 45280, 45307 (July 29, 2015) (adopting more stringent limits for glass-melting furnaces under a technology review where the EPA found that ''all glass-melting furnaces were achieving emission reductions that were well below the existing MACT standards regardless of the control technology in use''); *National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012) (adopting more stringent stack lead emission limit under a technology review ''based on emissions data collected from industry, which indicated that well-performing baghouses currently used by much of the industry are capable of achieving outlet lead concentrations significantly lower than the [current] limit.'').

[47] See figure 4 of the 2024 Technical Memo.

[48] See Document CLT–1T Testimony, CLT–11, and CL–12 in Docket 190882 at *https://www.utc.wa.gov/documents-and-proceedings/dockets.*

[49] See NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes, Docket No. 2019.09.058, Final Order 7708f paragraph 21 (November 18, 2020) (noting that ''Colstrip has a history of operating very close to the upper end limit''), available at *https://reddi.mt.gov/prweb.*

[50] For reference, a dekatherm is equivalent to one million Btus (MMBtu).

[51] See Document ID No. EPA–HQ–OAR–2018–5984 at *https://www.regulations.gov.*

operational in 2028 (see section 3 of the RIA for this final rule).

BILLING CODE 6560–50–P

Table 4. Summary of the Updated Cost Effectiveness Analysis for Three Potential fPM Limits[1]

	Potential fPM emission limit (lb/MMBtu)		
	0.015	0.010	0.006
Affected Units (Capacity, GW)	11 (4.7)	33 (14.1)	94 (41.3)
Annual Cost ($M, 2019 dollars)	38.8	87.2	398.8
fPM Reductions (tpy)	1,258	2,526	5,849
Total Non-Hg HAP Metals Reductions (tpy)	3.0	8.3	22.7
Total Non-Hg HAP Metals Cost Effectiveness ($k/ton)	13,050	10,500	17,500
Total Non-Hg HAP Metals Cost Effectiveness ($/lb)	6,500	5,280	8,790

[1] This analysis used reported fPM compliance data for 296 coal-fired EGUs to develop unit-specific average and lowest achieved fPM rate values to determine if the unit, with existing PM controls, could achieve a lower fPM limit. Using the compliance data, the EPA evaluated costs to upgrade existing PM controls, or if necessary, install new controls in order to meet a lower fPM limit.

BILLING CODE 6560–50–C

The EPA has updated its costs analyses for this final rule based on comments received and additional data review, which is described in more detail in the 2024 Technical Memo available in the docket. In response to commenters stating that the use of the lowest quarter's 99th percentile, or the lowest achievable fPM rate, is not indicative of overall EGU operation and emission performance, the EPA added a review of average fPM rates. In these updated analyses, both the lowest quarter's 99th percentile and the average fPM rate must be below the potential fPM limit for the EPA to assume no additional upgrades are needed to meet a revised limit. If an EGU has previously demonstrated an ability to meet a potential lower fPM limit, but the average fPM rate is greater than the potential limit, the analysis for the final rule has been updated to assume increased bag replacement frequency (for units with FFs) or operation and maintenance costing $100,000/year (2022$). This additional cost represents increased vigilance in maintaining ESP performance and includes technician labor to monitor performance of the ESP and to periodically make typical repairs (*e.g.,* replacement of failed insulators, damaged electrodes or other internals that may fail, repairing leaks in the ESP casing, ductwork, or expansion joints, and periodic testing of ESP flow balance and any needed adjustments).

Additionally, the Agency received comments that the PM upgrade costs estimated at proposal were too high on a dollar per ton basis and these costs have been updated and are provided in the 2024 Technical Memo. Specifically, commenters demonstrated that the observed percent reductions in fPM attributable to ESP upgrades were significantly greater than the percent reductions that the EPA had assumed for the proposed rule. Additionally, commenters demonstrated that ESP performance guarantees for coal-fired utility boilers were much lower than the EPA was aware of at proposal. These updates, as well as improving our methodology which increases the number of EGUs estimated to need PM upgrades, slightly lower the dollar per ton estimates from what was presented in the 2023 Proposal.

The EPA considers costs in various ways, depending on the rule and affected sector. For example, the EPA has considered, in previous CAA section 112 rulemakings, cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues (*e.g.,* cost to revenue ratios).[52] As much of the

[52] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Mercury Cell Chlor-Alkali Plants Residual Risk and Technology Review,* 87 FR 27002, 27008 (May 6, 2022) (considered annual costs and average capital costs per facility in technology review and beyond-the-floor analysis); *National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review,*

fleet is already reporting fPM emission rates below 0.010 lb/MMBtu, both the total costs and non-Hg HAP metal reductions of the revised limit are modest in context of total PM upgrade control costs and emissions of the coal fleet. The cost-effectiveness estimate for EGUs reporting average fPM rates above the final fPM emission limit of 0.010 lb/MMBtu is $10,500,000/ton of non-Hg HAP metals, slightly lower than the range presented in the 2023 Proposal.

Further, the EPA finds that costs for facilities to meet the revised fPM emission limit represent a small fraction of typical capital and total expenditures for the power sector. In the 2022 Proposal (reaffirming the appropriate and necessary finding), the EPA evaluated the compliance costs that were projected in the 2012 MATS Final Rule relative to the typical annual revenues, capital expenditures, and total (capital and production) expenditures.[53] 87 FR 7648–7659 (February 9, 2022); 80 FR 37381 (June 30, 2015). Using electricity sales data from the U.S. Energy Information Administration (EIA), the EPA updated the analysis presented in the 2022 Proposal. We find revenues from retail electricity sales increased from $333.5 billion in 2000 to a peak of $429.6 billion in 2008 (an increase of about 29 percent during this period) and slowly declined since to a post-2011 low of $388.6 billion in 2020 (a decrease of about 10 percent from its peak during this period) in 2019 dollars.[54] Revenues increased in 2022 to nearly the same amount as the 2008 peak ($427.8 billion). The annual control cost estimate for the final fPM standard based on the cost-effectiveness analysis in table 4 (see section 1c of the 2024 Technical Memo) of this document is a very small share of total power sector sales (about 0.03 percent of the lowest year over the 2000 to 2019 period). Making similar comparisons of the estimated capital and total compliance costs to historical trends in sector-level capital and production costs, respectively, would yield similarly small estimates. Therefore, as in previous CAA section 112 rulemakings, the EPA considered costs in many ways, including cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues to determine the appropriateness of the revised fPM standard under the CAA section 112(d)(6) technology review, and determined the costs are reasonable.

In this final rule, the EPA finds that costs of the final fPM standard are reasonable, and that the revised fPM standard appropriately balances the EPA's obligation under CAA section 112 to achieve the maximum degree of emission reductions considering statutory factors, including costs. Further, the EPA finds that its consideration of costs is consistent with D.C. Circuit precedent, which has found that CAA section 112(d)(2) expressly authorizes cost consideration in other aspects of the standard-setting process, such as CAA section 112(d)(6), *see Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013), and that CAA section 112 does not mandate a specific method of cost analysis in an analogous situation when considering the beyond-the-floor review. *See NACWA* v. *EPA,* 734 F.3d 1115, 1157 (D.C. Cir. 2013) (finding the statute did not ''mandate a specific method of cost analysis''); *see also NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014).

As discussed in section IV.C.1. in response to comments regarding the relatively higher dollar per ton cost effectiveness of the final fPM standard, the EPA finds that in the context of this industry and this rulemaking, the updated standards are an appropriate exercise of the EPA's standard setting authority pursuant to the CAA section 112(d)(6) technology review. As commenters rightly note, the EPA routinely considers the cost effectiveness of potential standards where it can consider costs under CAA section 112, *e.g.,* in conducting beyond-the-floor analyses and technology reviews, to determine the achievability of a potential control option. And the D.C. Circuit recognized that the EPA's interpretation of costs as ''allowing consideration of cost effectiveness was reasonable.'' *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014) (discussing the EPA's consideration of cost effectiveness pursuant to a CAA section 112(d)(2) beyond-the-floor analysis). However, cost effectiveness is not the sole factor that the EPA considers when determining the achievability of a potential standard in conducting a technology review, nor is cost effectiveness the only value that the EPA considers with respect to costs.[55] Some commenters pointed to other rulemakings (which are discussed in section IV.C.1. above) where the EPA determined not to pursue potential control options with relatively higher cost-effectiveness estimates as compared to prior CAA section 112 rulemakings. However, there were other factors that the EPA considered, in addition to cost effectiveness, that counseled against pursuing such updates. In this rulemaking, the EPA finds that several factors discussed throughout this record make promulgation of the new fPM standard appropriate under CAA section 112(d)(6). First, a wide majority of units have invested in the most-effective PM controls and are already demonstrating compliance with the new fPM standard and at lower costs than assumed during promulgation of the original MATS fPM emission limit. Of the 33 EGUs that the EPA estimated would require control improvements to meet a 0.010 lb/MMBtu fPM standard, only two are not using the most effective PM control technologies available. The EPA assumed that these two units would need to install FFs to achieve the 0.010 lb/MMBtu emission standard, and the cost of those FF retrofits accounts for 42 percent of the total annualized costs presented in table 4. Further, 11 EGUs that the EPA assumed would require different levels of ESP upgrades to meet the 0.010 lb/MMBtu emission standard (all of which have announced retirement dates between 2031 and 2042 resulting in shorter assumed amortization periods) account for about 57 percent of the total annualized costs. The remaining 1 percent of the total annualized costs are associated with 10 EGUs with existing FFs that the EPA

87 FR 1616, 1635 (proposed January 11, 2022) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in proposed beyond-the-floor analysis); *Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing,* 80 FR 50386, 50398 (August 19, 2015) (considered total annual costs and capital costs compliance costs and annualized costs for technology review and beyond the floor analysis); *National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in technology review); *National Emission Standards for Hazardous Air Pollutants: Off-Site Waste and Recovery Operations,* 80 FR 14248, 14254 (March 18, 2015) (considered total annual costs and capital costs, and average annual costs and capital costs and annualized costs per facility in technology review); *National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants,* 77 FR 58220, 58226 (September 19, 2012) (considered total annual costs and capital costs in technology review); *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,* 77 FR 49490, 49523 (August 16, 2012) (considered total capital costs and annualized costs and capital costs in technology review). *C.f. NRDC* v. *EPA,* 749 F.3d 1055, 1060 (D.C. Cir. 2014).

[53] See Cost TSD for 2022 Proposal at Document ID No. EPA–HQ–OAR–2018–0794–4620 at *https://www.regulations.gov.*

[54] 2019 dollars were used for consistency with the 2023 Proposal.

[55] See note 50, above, for examples of other costs metrics the EPA has considered in prior CAA section 112 rulemakings.

assumes will require bag upgrades or increased bag changeouts and 10 EGUs that are assumed to need additional operation and maintenance of existing ESPs, which is further explained in the 2024 Technical Memo. Since only a small handful of units emit significantly more than peer facilities, the Agency finds these upgrades appropriate. Additionally, the size and unique nature of the coal-fired power sector, and the emission reductions that will be achieved by the new standard, in addition to the costs, make promulgation of the new standard appropriate under CAA section 112(d)(6).

The power sector also operates differently than other industries regulated under CAA section 112.[56] For example, the power sector is publicly regulated, with long-term decision-making and reliability considerations made available to the public; it is a data-rich sector, which generally allows the EPA access to better information to inform its regulation; and the sector is in the midst of an energy generation transition leading to plant retirements that are independent of EPA regulation. Because of the relative size of the power sector, while cost effectiveness of the final standard is relatively high as compared to prior CAA section 112 rulemakings involving other industries, costs represent a much smaller fraction of industry revenue. In the likely case that the power sector's transition to lower-emitting generation is accelerated by the IRA, for example, the total costs and emission reductions achieved by each final fPM standard in table 4 of this document would also be an overestimate.

As demonstrated in the proposal, the power sector, as a whole, is achieving fPM emission rates that are well below the 0.030 lb/MMBtu standard from the 2012 Final MATS Rule, with the exception of a few outlier facilities. The EPA estimates that only one facility (out of the 151 evaluated coal-fired facilities), which does not have the most modern PM pollution controls and has been unable to demonstrate an ability to meet a lower fPM limit, will be required to install the most-costly upgrade to meet the revised standards, which significantly drives up the cost of this final rule. However, the higher costs for one facility to install demonstrated improvements to its control technology should not prevent the EPA from establishing achievable standards for the sector under the EPA's CAA section 112(d)(6) authority. Instead, the EPA finds that it is consistent with its CAA section 112(d)(6) authority to consider the performance of the industry at large. The average fPM emissions of the industry demonstrate the technical feasibility of higher emitting facilities to meet the new standard and shows there are proven technologies that if installed at these units will allow them to significantly lower fPM and non-Hg HAP metals emissions.

In this rulemaking, the EPA also determined not to finalize a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu or lower, which the EPA took comment on in the 2023 Proposal. The EPA declines to finalize an emission standard of 0.006 lb/MMBtu or lower primarily due to technical limitations in using PM CEMS for compliance demonstration purposes described in the next section. The EPA has determined that a fPM emission standard of 0.010 lb/MMBtu is the lowest that would also allow the use of PM CEMS for compliance demonstration. Additionally, the EPA also considered the overall higher costs associated with a more stringent standard as compared to the final standard, which the EPA considered under the technology review.

Additionally, compliance with a fPM emission limit of 0.006 lb/MMBtu could only be demonstrated using periodic stack testing that would require test run durations longer than 4 hours[57] and would not provide the source, the public, and regulatory authorities with continuous, transparent data for all periods of operation. Establishing a fPM limit of 0.006 lb/MMBtu while maintaining the current compliance demonstration flexibilities of quarterly ''snapshot'' stack testing would, theoretically, result in greater emission reductions; however, the measured emission rates are only representative of rates achieved at optimized conditions at full load. While coal-fired EGUs have historically provided baseload generation, they are being dispatched much more as load following generating sources due to the shift to more available and cheaper natural gas and renewable generation. As such, traditional generation assets—such as coal-fired EGUs—will likely continue to have more startup and shutdown periods, more periods of transient operation as load following units, and increased operation at minimum levels, all of which can produce higher PM emission rates. Maintaining the status quo with quarterly stack testing will likely mischaracterize emissions during these changing operating conditions. Thus, while a fPM emission limit of 0.006 lb/MMBtu paired with use of quarterly stack testing may appear to be more stringent than the 0.010 lb/MMBtu standard paired with use of PM CEMS that the EPA is finalizing in this rule, there is no way to confirm emission reductions during periods in between quarterly tests when emission rates may be higher. Therefore, the Agency is finalizing a fPM limit of 0.010 lb/MMBtu with the use of PM CEMS as the only means of compliance demonstration. The EPA has determined that this combination of fPM limit and compliance demonstration represents the most stringent available option taking into account the statutory considerations.

The EPA also determined not to finalize a fPM standard of 0.015 lb/MMBtu, which the EPA took comment on in the 2023 Proposal, because the EPA determined that a standard of 0.010 lb/MMBtu is appropriate for the reasons discussed above.

In this rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the fPM emission standard and requirements to utilize PM CEMS. As discussed in section II.D. above, the 2020 Technology Review did not consider developments in the cost and effectiveness of proven technologies to control fPM as a surrogate for non-Hg HAP metals emissions, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs. In this rulemaking, in which the EPA reviewed the findings of the 2020 Technology Review, the Agency determined there are important developments regarding the emissions performance of the coal-fired EGU fleet, and the costs of achieving that performance that are appropriate for the EPA to consider under its CAA section 112(d)(6) authority, and which are the basis for the revised emissions standards the EPA is promulgating through this final rule.

The 2012 MATS Final Rule contains emission limits for both individual and total non-Hg HAP metals (*e.g.,* lead, arsenic, chromium, nickel, and cadmium), as well as emission limits for fPM. Those non-Hg HAP metals

[56] This is a fact which Congress recognized in requiring the EPA to first determine whether regulation of coal-fired EGUs was ''appropriate and necessary'' under CAA section 112(n)(1)(A) before proceeding to regulate such facilities under CAA section 112's regulatory scheme.

[57] Run durations greater than 4 hours would ensure adequate sample collection and lower random error contributions to measurement uncertainty for a limit of 0.006 lb/MMBtu. The EPA aims to keep run durations as short as possible, generally at least one but no more than 4 hours in length, in order to minimize impacts to the facility (*e.g.,* overall testing campaign testing costs, employee focused attention and safety).

emission limits serve as alternative emission limits because fPM was found to be a surrogate for either individual or total non-Hg HAP metals emissions. While EGU owners or operators may choose to demonstrate compliance with either the individual or total non-Hg HAP metals emission limits, the EPA is aware of just one owner or operator who has provided non-Hg HAP metals data—both individual and total—along with fPM data, for compliance demonstration purposes. This is for a coal refuse-fired EGU with a generating capacity of 46.1 MW. Given that owners or operators of all the other EGUs that are subject to the requirements in MATS have chosen to demonstrate compliance with only the fPM emission limit, the EPA proposed to remove the total and individual non-Hg HAP metals emission limits from all existing MATS-affected EGUs and solicited comment on our proposal. In the alternative, the EPA took comment on whether to retain total and/or individual non-Hg HAP metals emission limits that have been lowered proportionally to the revised fPM limit (*i.e.,* revised lower by two-thirds to be consistent with the revision of the fPM standard from 0.030 lb/MMBtu to 0.010 lb/MMBtu).

Commenters urged the EPA to retain the non-Hg HAP metals limits, arguing it is incongruous for the EPA to eliminate the measure for the pollutants that are the subject of regulation under CAA section 112(d)(6), notwithstanding the fact that the fPM limit serves as a more easily measurable surrogate for these HAP metals. Additionally, some commenters stated that the inability to monitor HAP metals directly will significantly impair the EPA's ability to revise emission standards in the future.

After considering comments, the EPA determined to promulgate revised total and individual non-Hg HAP metals emission limits for coal-fired EGUs that are lowered proportionally to the revised fPM standard. Just as this rule requires owners or operators to demonstrate continuous compliance with fPM limits, owners or operators who choose to demonstrate compliance with these alternative limits will need to utilize approaches that can measure non-Hg HAP metals on a continuous basis—meaning that intermittent emissions testing using Reference Method 29 will not be a suitable approach. Owners or operators may petition the Administrator to utilize an alternative test method that relies on continuous monitoring (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f). The EPA disagrees with the suggestion that failure to monitor HAP metals directly could impair the ability to revise those standards in the future.

2. Rationale for the Final Compliance Demonstration Options

In the 2023 Proposal, the EPA proposed to require that coal- and oil-fired EGUs utilize PM CEMS to demonstrate compliance with the fPM standard used as a surrogate for non-Hg HAP metals. The EPA proposed the requirement for PM CEMS based on its assessment of costs of PM CEMS versus stack testing, and the many other benefits of using PM CEMS including increased transparency and accelerated identification of anomalous emissions. In particular, the EPA noted the ability for PM CEMS to provide continuous feedback on control device and plant operations and to provide EGU owners and operators, regulatory authorities, and members of nearby communities with continuous assurance of compliance with emissions limits as an important benefit. Further, the EPA explained in the 2023 Proposal that PM CEMS are currently in use by approximately one-third of the coal-fired fleet, and that PM CEMS can provide low-level measurements of fPM from existing EGUs.

After considering comments and conducting further analysis,[58] the EPA is finalizing the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs pursuant to its CAA section 112(d)(6) authority. As discussed in section IV.D.1. above, Congress intended for CAA section 112 to achieve significant reductions in HAP, which it recognized as particularly harmful pollutants. The EPA finds that the benefits of PM CEMS to provide real-time information to owners and operators (who can promptly address any problems with emissions control equipment), to regulators, to adjacent communities, and to the general public, further Congress's goal to ensure that emission reductions are consistently maintained. The EPA determined not to require PM CEMS for existing IGCC EGUs, described in section VI.D., due to technical issues calibrating CEMS on these types of EGUs due to the difficulty in preparing a correlation range because these EGUs are unable to de-tune their fPM controls and their existing emissions are less than one-tenth of the final emission limit. Further, the EPA finds additional authority to require the use of PM CEMS under CAA section 114(a)(1)(C), which allows that the EPA may require a facility that ''may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter'' to ''install, use, and maintain such monitoring equipment'' on a ''on a one-time, periodic or continuous basis.'' 114(a)(1)(C).

From the EPA's review of PM CEMS, the Agency determined that a fPM standard of 0.010 lb/MMBtu with adjusted QA criteria—used to verify consistent correlation of CEMS data initially and over time—is the lowest fPM emission limit possible at this time with use of PM CEMS.[59] PM CEMS correlated using these values will ensure accurate measurements—either above, at, or below this emission limit. As discussed in section IV.D.1. above, one of the reasons the EPA determined not to finalize a more stringent standard for fPM is because it would prove challenging to verify accurate measurement of fPM using PM CEMS. Specifically, as mentioned in the *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels,* memorandum, available in the docket, no fPM standard more stringent than 0.010 lb/MMBtu with adjusted QA criteria is expected to have acceptable passing rates for the QA checks or acceptable random error for reference method testing.

At proposal, the EPA estimated that the EUAC of PM CEMS was $60,100 (88 FR 24873). Based on comments the EPA received on the costs and capabilities of PM CEMS and additional analysis the EPA conducted, the EPA determined that the revised EUAC of PM CEMS is higher than estimated at proposal. The EPA now estimates that the EUAC of non-beta gauge PM CEMS is $72,325, which is 17 percent less than what was estimated for the 2012 MATS Final Rule. That amount is somewhat greater than the revised estimated costs of infrequent emission testing (generally quarterly)—the revised average estimated costs of such infrequent emissions testing using EPA Method 5I[60] is $60,270.[61]

In choosing a compliance demonstration requirement, the EPA considers multiple factors, including

[58] The EPA explains additional analyses of PM CEMS in the memos titled *Suitability of PM CEMS Use for Compliance Determination for Various Emissions Levels* and *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, appendices B and F, respectively,* which are available in the docket.

[59] The EPA notes that the fPM standard [0.010 lb/MMBtu] is based on hourly averages obtained from PM CEMS over 30 boiler operating days [see 40 CFR 63.10021(b)].

[60] Method 5I is one of the EPA's reference test methods for PM. See 40 CFR part 60, appendix A.

[61] See *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* memorandum, available in the docket.

costs, benefits of the compliance technique, technical feasibility and commercial availability of the compliance method, ability of personnel to conduct the compliance method, and continuity of data used to assure compliance. PM CEMS are readily available and in widespread use by the electric utility industry, as evidenced by the fact that over 100 EGUs already utilize PM CEMS for compliance demonstration purposes. Moreover, the electric utility industry and its personnel have demonstrated the ability to install, operate, and maintain numerous types of CEMS—including PM CEMS. As mentioned earlier, EGU owners and/or operators who chose PM CEMS for compliance demonstration have attested in their submitted reports to the suitability of their PM CEMS to measure at low emission levels, certifying fPM emissions lower than 0.010 lb/MMBtu with their existing correlations developed using emission levels at 0.030 lb/MMBtu. The EPA conducted a review of eight EGUs with varying fPM control devices that rely on PM CEMS that showed certified emissions ranging from approximately 0.002 lb/MMBtu to approximately 0.007 lb/MMBtu. The EPA's review analyzed 30 boiler operating day rolling averages obtained from reports posted to WebFIRE for the third quarter of 2023 from these eight EGUs.[62]

As described in the *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, Appendices B and F* memorandum, available in the docket, the EPA investigated how well a sample of EGUs using PM CEMS for compliance purposes would meet initial and ongoing QA requirements at various emission limit levels, even though no change in actual EGU operation occurred. As described in the aforementioned *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels* memorandum, as the emission limit is lowered, the ability to meet both components necessary to correlate PM CEMS—acceptable random error and QA passing rate percentages—becomes more difficult. Based on this additional analysis and review, the EPA determined to finalize requirements to use PM CEMS with adjusted QA criteria and a 0.010 lb/MMBtu fPM emission limit as the most stringent limit possible with PM CEMS.

Use of PM CEMS can provide EGU owners or operators with an increased ability to detect and correct potential problems before degradation of emission control equipment, reduction or cessation of electricity production, or exceedances of regulatory emission standards. As mentioned in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, using PM CEMS can be advantageous, particularly since their EUAC is offset if their use allows owners or operators to avoid 3 or more hours of generating downtime per year.

In deciding whether to finalize the proposal to use PM CEMS as the only compliance demonstration method for non-IGCC coal- and oil-fired EGUs, the Agency assessed the costs and benefits afforded by requiring use of only PM CEMS as compared to continuing the current compliance demonstration flexibilities (*i.e.,* allowing use of either PM CEMS or infrequent PM emissions stack testing). As mentioned above, the average annual cost for quarterly stack testing provided by commenters is about $12,000 less than the EUAC for PM CEMS. While no estimate of quantified benefits was provided by commenters, the EPA recognizes that the 35,040 15-minute values provided by a PM CEMS used at an EGU operating during a 1-year period is over 243 times as much information as is provided by quarterly testing with three 3-hour run durations. This additional, timely information provided by PM CEMS affords the adjacent communities, the general public, and regulatory authorities with assurances that emission limits and operational processes remain in compliance with the rule requirements. It also provides EGU owners or operators with the ability to quickly detect, identify, and correct potential control device or operational problems before those problems become compliance issues. When establishing emission standards under CAA section 112, the EPA must select an approach to compliance demonstration that best assures compliance is being achieved.

The continuous monitoring of fPM required in this rule provides several benefits which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today. Continuous measurement of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that continuous monitoring could lead to lower fPM emissions for periods of time between otherwise required intermittent testing, currently up to 3 years for some units.

To illustrate the potentially substantial differences in fPM emissions between intermittent and continuous monitoring, the EPA analyzed emissions at several EGUs for which both intermittent and continuous monitoring data are available. This analysis is provided in the 2024 Technical Memo, available in the rulemaking docket. For example, one 585-MW bituminous-fired EGU, with a cold-side ESP for PM control, has achieved LEE status for fPM and is currently required to demonstrate compliance with an emission standard of 0.015 lb/MMBtu using intermittent stack testing every 3 years. In the most recent LEE compliance report, submitted on February 25, 2021, the unit submitted the result of an intermittent stack test with an emission rate of 0.0017 lb/MMBtu. In the subsequent 36 months over which this unit is currently not subject to any further compliance testing, continuous monitoring demonstrates that the fPM emission rate increased substantially. At one point, the continuously monitored 30-day rolling average emissions rate[63] was nine times higher than the intermittent stack test average, reaching the fPM LEE limit of 0.015 lb/MMBtu. In this example, the actual continuously monitored daily average emissions rate over the February 2021 to April 2023 period ranged from near-zero to 0.100 lb/MMBtu. Emissions using either the stack test average or hourly PM CEMS data were calculated for 2022 for this unit. Both approaches indicate fPM emissions well below the allowable levels for a fPM limit of 0.010 lb/MMBtu, while estimates using PM CEMS are about 2.5 times higher than the stack test estimate. Additional examples of differences between intermittent stack testing and continuous monitoring are provided in the 2024 Technical Memo, including for periods when PM CEMS data is lower

[62] See Third Quarter 2023 p.m. CEMS Thirty Boiler Operating Day Rolling Average Reports for Iatan Generating Station units 1 and 2, Missouri; Marshall Steam Station units 1 and 3, North Carolina; Kyger Creek Station unit 3, Ohio; Virginia City Hybrid Energy Center units 1 and 2, Virginia; and Ghent Generating Station unit 1, Kentucky. These reports are available electronically by searching in the WebFIRE Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[63] The 30-day rolling average emission rate was calculated by taking daily fPM rate averages over a 30-day operating period while filtering out hourly fPM data during periods of startup and shutdown.

than the stack test averages,[64] which further illustrate real-life scenarios in which fPM emissions for compliance methods may be substantially different.

The potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the total capacity that the EPA estimates would install PM CEMS under this rule (nearly 82 GW). Furthermore, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living in proximity to the coal-fired EGUs potentially impacted by the amended fPM standards. The EPA has found that populations living near coal-fired EGUs have a higher percentage of people living below two times the poverty level than the national average.

In addition to significant value of further pollution abatement, the CEMS data are transparent and accessible to regulators, stakeholders, and the public, fostering greater accountability. Transparency of EGU emissions as provided by PM CEMS, along with real-time assurance of compliance, has intrinsic value to the public and communities as well as instrumental value in holding sources accountable. This transparency is facilitated by a requirement for electronic reporting of fPM emissions data by the source to the EPA. This emissions data, once submitted, becomes accessible and downloadable—along with other operational and emissions data (*e.g.,* for SO_2, CO_2, NO_X, Hg, *etc.*) for each covered source.

On balance, the Agency finds that the benefits of emissions transparency and the continuous information stream provided by PM CEMS coupled with the ability to quickly detect and correct problems outweigh the minor annual cost differential from quarterly stack testing. The EPA is finalizing, as proposed, the use of PM CEMS to demonstrate compliance with the fPM emission standards for coal- and oil-fired EGUs (excluding IGCC units and limited-use liquid-oil-fired EGUs).

More information on the proposed technology review can be found in the 2023 Technical Memo (Document ID No. EPA–HQ–OAR–2018–0794–5789), in the preamble for the 2023 Proposal (88 FR 24854), and the 2024 Technical Memo, available in the docket. For the reasons discussed above, pursuant to CAA section 112(d)(6), the EPA is finalizing, as proposed, the use of PM CEMS (with adjusted QA criteria as a result of review of comments) for the compliance demonstration of the fPM emission standard (as a surrogate for non-Hg HAP metal) for coal- and oil-fired EGUs, and the removal of the fPM and non-Hg HAP metals LEE provisions.

V. What is the rationale for our final decisions and amendments to the Hg emission standard for lignite-fired EGUs from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the lignite-fired EGU subcategory?

In the 2012 MATS Final Rule, the EPA finalized a Hg emission standard of 4.0E-06 lb/MMBtu (4.0 lb/TBtu) for a subcategory of existing lignite-fired EGUs.[65] The EPA also finalized a Hg emission standard of 1.2E-06 lb/MMBtu (1.2 lb/TBtu) for coal-fired EGUs not firing lignite (*i.e.,* for EGUs firing anthracite, bituminous coal, subbituminous coal, or coal refuse); and the EPA finalized a Hg emission output-based standard for new lignite-fired EGUs of 0.040 lb/GWh and a Hg emission output-based standard for new non-lignite-fired EGUs of 2.0E-04 lb/GWh. In 2013, the EPA reconsidered the Hg emission standard for new non-lignite-fired EGUs and revised the output-based standard to 0.003 lb/GWh (see 78 FR 24075).

As explained in the 2023 Proposal, Hg emissions from the power sector have declined since promulgation of the 2012 MATS Final Rule with the installation of Hg-specific and other control technologies and as more coal-fired EGUs have retired or reduced utilization. The EPA estimated that 2021 Hg emissions from coal-fired EGUs were 3 tons (a 90 percent decrease compared to pre-MATS levels). However, units burning lignite (or permitted to burn lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in table 5 in the 2023 Proposal (88 FR 24876), 16 of the top 20 Hg-emitting EGUs in 2021 were lignite-fired EGUs. Overall, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs in 2021, while generating about 7 percent of total 2021 megawatt-hours. Lignite accounted for 8 percent of total U.S. coal production in 2021.

Prior to the 2023 Proposal, the EPA assembled information on developments in Hg emission rates and installed controls at lignite-fired EGUs from operational and emissions information that is provided routinely to the EPA for demonstration of compliance with MATS and from information provided to the EIA. In addition, the EPA's final decisions were informed by information that was submitted as part of a CAA section 114 information survey (2022 ICR). The EPA also revisited information that was used in establishing the emission standards in the 2012 Final MATS Rule and considered information that was submitted during the public comment period for the 2023 Proposal. From that information, the EPA determined, as explained in the 2023 Proposal, that there are available cost-effective control technologies and improved methods of operation that would allow existing lignite-fired EGUs to achieve a more stringent Hg emission standard. As such, the EPA proposed a revised Hg emission standard for existing EGUs firing lignite (*i.e.,* for those in the ''units designed for low rank virgin coal'' subcategory). Specifically, the EPA proposed that such lignite-fired units must meet the same emission standard as existing EGUs firing other types of coal (*e.g.,* anthracite, bituminous coal, subbituminous coal, and coal refuse), which is 1.2 lb/TBtu (or an alternative output-based standard of 0.013 lb/GWh). The EPA did not propose to revise the Hg emission standards either for existing EGUs firing non-lignite coal or for new non-lignite coal-fired EGUs.[66]

B. How did the technology review change for the lignite-fired EGU subcategory?

The outcome of the technology review for the Hg standard for existing lignite-fired EGUs has not changed since the 2023 Proposal. However, in response to comments, the EPA expanded its review to consider additional coal compositional data and the impact of sulfur trioxide (SO_3) in the flue gas.

[64] See Case Study 2 in the 2024 Technical Memo, which shows long time periods of PM CEMS data below the most recent RRA. Note this unit uses PM CEMS for compliance with the fPM standard, so the RRA is used as an indicator of stack test results.

[65] The EPA referred to this subcategory in the final rule as ''units designed for low rank virgin coal.'' The EPA went on to specify that such a unit is designed to burn and is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal. The EPA also finalized an alternative output-based emission standard of 0.040 lb/GWh. Currently, the approximately 22 units that are permitted as lignite-fired EGUs are located exclusively in North Dakota, Texas, and Mississippi.

[66] As stated in the 2023 Proposal, when proposed revisions to existing source emission standards are more stringent than the corresponding new source emission standard, the EPA proposes to revise the corresponding new source standard to be at least as stringent as the proposed revision to the existing source standard. This is the case with the Hg emission standard for new lignite-fired sources, which will be adjusted to be as stringent as the existing source standard.

C. What key comments did we receive on the Hg emission standard for lignite-fired EGUs, and what are our responses?

The Agency received both supportive and critical comments on the proposed revision to the Hg emission standard for existing lignite-fired EGUs. Some commenters agreed with the EPA's decision to not propose revisions to the Hg emission standards for non-lignite-fired EGUs, while others disagreed. Significant comments are summarized below, and the Agency's responses are provided.

Comment: Several commenters stated that industry experience confirms that stringent limits on power plant Hg emissions can be readily achieved at lower-than-predicted costs and thus should be adopted nationally through CAA section 112(d)(6). They said that at least 14 states have, for years, enforced state-based limits on power plant Hg emissions, and nearly every one of those states has imposed more stringent emission limits than those proposed in this rulemaking or in the final 2012 MATS Final Rule. The commenters said that these lower emissions limits have resulted in significant and meaningful Hg emission reductions, which have proven to be both achievable and cost-effective.

Some commenters recommended that the EPA revise the Hg limits to levels that are much more stringent than existing or proposed standards for both EGUs firing non-lignite coals and those firing lignite. They claimed that more stringent Hg emission standards are supported by developments in practices, processes, and control technologies. They pointed to a 2021 report by Andover Technology Partners, which details advances in control technologies that support more stringent Hg standards for all coal-fired EGUs.[67] These advances include advanced activated carbon sorbents with higher capture capacity at lower injection rates and carbon sorbents that are tolerant of flue gas species.

Response: The EPA has taken these comments and the referenced information into consideration when establishing the final emission standards. The EPA disagrees that the Agency should, in this final rule, revise the Hg limits for all coal-fired EGUs to levels more stringent than the current or proposed standards. The Agency did not propose in the 2023 Proposal to revise the Hg emission standard for ''not-low-rank coal units'' (*i.e.,* those EGUs that are firing on coals other than lignite) and did not suggest an emission standard for lignite-fired EGUs more stringent than the 1.2 lb/TBtu emission standard that was proposed. However, the EPA will continue to review emission standards and other rule requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If we determine in subsequent CAA section 112(d)(6) technology reviews that further revisions to Hg emission standards (or to standards for other HAP or surrogate pollutants) are warranted, then we will propose revisions at that time. We discuss the rationale for the final emission standards in section V.D. of this preamble and in more detail in the 2024 Technical Memo.

Comment: Several commenters challenged the data that the EPA used in the CAA 112(d)(6) technology review. Commenters stated that the information collected by the EPA via the CAA section 114 request consisted of 17 units each submitting two 1-week periods of data and associated operational data preselected by the EPA, and that only a limited number of the EGUs reported burning only lignite. Other EGUs reported burning primarily refined coal, co-firing with natural gas, and firing or co-firing with large amounts of subbituminous coal (referencing table 7 in the 2023 Proposal). Commenters stated that if the EPA's intent was to assess the Hg control performance of lignite-fired EGUs, then the EGUs evaluated should have burned only lignite, not refined coal, subbituminous coal, or natural gas.

Response: The EPA disagrees with the commenters' argument that the Agency should have only considered emissions and operational data from EGUs that were firing only lignite. The EPA's intent was to evaluate the Hg emission control performance of units that are permitted to burn lignite and are thus subject to a Hg emission standard of 4.0 lb/TBtu. According to fuel use information supplied to EIA on form 923,[68] 13 of 22 EGUs that were designed to burn lignite utilized ''refined coal'' to some extent in 2021, as summarized in table 7 in the 2023 Proposal preamble (88 FR 24878). EIA form 923 does not specify the type of coal that is ''refined'' when reporting boiler or generator fuel use. For the technology review, the EPA assumed that the facilities utilized ''refined lignite,'' as reported in fuel receipts on EIA form 923. In any case, firing of refined lignite or subbituminous coal or co-firing with natural gas or fuel oil are considered to be Hg emission reduction strategies for a unit that is subject to an emission standard of 4.0 lb/TBtu, which was based on the use of lignite as its fuel.

In a related context, in *U.S. Sugar Corp.* v. *EPA,* the D.C. Circuit held that the EPA could not exclude unusually high performing units within a subcategory from the Agency's determination of MACT floor standards for a subcategory pursuant to CAA section 112(d)(3). 830 F.3d 579, 631–32 (D.C. Cir. 2016) (finding ''an unusually high-performing source should be considered[,]'' in determining MACT floors for a subcategory, and that ''its performance suggests that a more stringent MACT standard is appropriate.''). While the technology review at issue here is a separate and distinct analysis from the MACT floor setting requirements at issue in *U.S. Sugar* v. *EPA,* similarly here the EPA finds it is appropriate to consider emissions from all units that are permitted to burn lignite and are therefore subject to the prior Hg emission standard of 4.0 lb/TBtu and are part of the lignite-fired EGU subcategory, for the purposes of determining whether more stringent standards are appropriate under a technology review. However, while the EPA has considered the emissions performance of all units within the lignite-fired EGU subcategory, it is not the performance of units that are firing or co-firing with other non-lignite fuels that provide the strongest basis for the more stringent standard. Rather, the most convincing evidence to support the more stringent standard is that there are EGUs that are permitted to fire lignite—and are only firing lignite—that have demonstrated an ability to meet the more stringent standard of 1.2 lb/TBtu.

Comment: Several commenters claimed that, rather than using actual measured Hg concentrations in lignite that had been provided in the CAA section 114 request responses (and elsewhere), the EPA used Integrated Planning Model (IPM) data to assign inlet Hg concentrations to various lignite-fired EGUs. Some commenters asserted that the actual concentration of Hg in lignite is higher than those assumed by the EPA and that there is considerable variability in the concentration of Hg in the lignite used in these plants. As a result, the commenters claimed, the percent Hg capture needed to achieve the proposed 1.2 lb/TBtu emission standard would be higher than that assumed by the EPA in the 2023 Proposal.

[67] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[68] *https://www.eia.gov/electricity/data/eia923/.*

Response: In the 2023 Proposal, the EPA assumed a Hg inlet concentration (*i.e.,* concentration of Hg in the fuel) that reflected the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the IPM. In response to comments received on the proposal, the EPA has modified the Hg inlet concentration assumptions for each unit to reflect measured Hg concentrations in lignite using information provided by commenters and other sources, including measured Hg concentrations in fuel samples from the Agency's 1998 Information Collection Request (1998 ICR). This is explained in additional detail below in section V.D.1. and in a supporting technical memorandum titled *1998 ICR Coal Data Analysis Summary of Findings.* However, this adjustment in the assumed concentration of Hg in the various fuels did not change the EPA's overall conclusion that there are available controls and improved methods of operation that will allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu.

Comment: Some commenters claimed that the Agency failed to account for compositional differences in lignite as compared to those of other types of coal—especially in comparison to subbituminous coal.

Response: The EPA disagrees with these commenters. In the 2023 Proposal, the EPA emphasized the similarities between lignite and subbituminous coal—especially regarding the fuel properties that most impact the control of Hg. The EPA noted that lignite and subbituminous coal are both low rank coals with low halogen content and explained that the halogen content of the coal—especially chlorine—strongly influences the oxidation state of Hg in the flue gas stream and, thereby, directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. The EPA further noted that the fly ashes from lignite and subbituminous coals tend to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and to the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. Due to the natural alkalinity, subbituminous and lignite fly ashes can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of gaseous elemental Hg vapor (Hg^0). This lack of free halogen in the flue gas challenges the control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs as compared to the Hg control of EGUs firing bituminous coal. The EPA noted in the 2023 Proposal, however, that control strategies and control technologies have been developed and utilized to introduce halogens to the flue gas stream, and that EGUs firing subbituminous coals have been able to meet (and oftentimes emit at emission rates that are considerably lower than) the 1.2 lb/TBtu emission standard in the 2012 MATS Final Rule. Therefore, while the EPA acknowledges that there are differences in the composition of the various coal types, there are available control technologies that allow EGUs firing any of those coal types to achieve an emission standard of 1.2 lb/TBtu. The EPA further notes that North Dakota and Texas lignites are much more similar in composition and in other properties to Wyoming subbituminous coal than either coal type is to eastern bituminous coal. Both lignite and subbituminous coal are lower heating value fuels with high alkaline content and low natural halogen. In contrast, eastern bituminous coals are higher heating value fuels with high natural halogen content and low alkalinity. But while Wyoming subbituminous coal is much more similar to lignite than it is to eastern bituminous coals, EGUs firing subbituminous coal must meet the same Hg emission standard (1.2 lb/TBtu) as EGUs firing bituminous coal. The EPA further acknowledges the differences in sulfur content between subbituminous coal and lignite and its impact is discussed in the following comment summary and response.

Comment: Some commenters claimed that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. The commenters noted that the presence of SO_3 is known to negatively impact the effectiveness of activated carbon for Hg control.

Response: The EPA agrees with the commenters that the Agency did not fully address the potential impacts of SO_3 on the control of Hg from lignite-fired EGUs in the 2023 Proposal. However, in response to these comments, the EPA conducted a more robust evaluation of the impact of SO_3 in the flue gas of lignite-fired EGU and determined that it does not affect our previous determination that there are control technologies and methods of operation that are available to EGUs firing lignite that would allow them to meet a Hg emission standard of 1.2 lb/TBtu—the same emission standard that must be met by EGUs firing all other types of coal. As discussed in more detail below, the EPA determined that there are commercially available advanced ''SO_3 tolerant'' Hg sorbents and other technologies that are specifically designed for Hg capture in high SO_3 flue gas environments. These advanced sorbents allow for capture of Hg in the presence of SO_3 and other challenging flue gas environments at costs that are consistent with the use of conventional pre-treated activated carbon sorbents.[69] The EPA has considered the additional information regarding the role of flue gas SO_3 on Hg control and the information on the availability of advanced ''SO_3 tolerant'' Hg sorbents and other control technologies and finds that this new information does not change the Agency's determination that a Hg emission standard of 1.2 lb/TBtu is achievable for lignite-fired EGUs.

Comment: Several commenters noted the EPA made improper assumptions to reach the conclusion that the revised Hg emissions limit is achievable and claimed that none of the 22 lignite-fired EGUs are currently in compliance with the proposed 1.2 lb/TBtu Hg emission standard and that the EPA has not shown that any EGU that is firing lignite has demonstrated that it can meet the proposed Hg emission standard.

Response: The EPA disagrees with commenters' assertion and maintains that the Agency properly determined that the proposed, more stringent Hg emission standard can be achieved, cost-effectively, using available control technologies and improved methods of operation. Further, the EPA notes that, contrary to commenters' claim, there are, in fact, EGUs firing lignite that have demonstrated an ability to meet the more stringent 1.2 lb/TBtu Hg emission standard. Twin Oaks units 1 and 2 are lignite-fired EGUs operated by Major Oak Power, LLC, and located in Robertson County, Texas. In the 2023 Proposal (see 88 FR 24879 table 8), we showed that 2021 average Hg emission rates for Twin Oaks 1 and 2 (listed in the table as Major Oak #1 and Major Oak #2) were 1.24 lb/TBtu and 1.31 lb/TBtu, respectively, which are emission rates that are just slightly above the final emission limit. Both units at Major Oak have qualified for LEE status for Hg. To demonstrate LEE status for Hg an EGU owner/operator must conduct an initial EPA Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit (PTE) that is less than 10 percent of the applicable Hg emissions limit (for

[69] See Tables 8 and 9 from ''Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants'', Andover Technology Partners (August 2021); available in the rulemaking docket at Docket ID: EPA–HQ–OAR–2018–4583.

lignite-fired EGUs this would be a rate of 0.40 lb/TBtu) *or* less than 29 lb of Hg per year. If an EGU qualifies as a LEE for Hg, then the owner/operator must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. In their most recent compliance reports [70] (dated November 14, 2023), Major Oak Power, LLC, summarized the performance testing. Between August 1 and September 19, 2023, Major Oak Power, LLC, personnel performed a series of performance tests for Hg on Twin Oaks units 1 and 2. The average Hg emissions rate for the 30-boiler operating day performance tests was 1.1 lb/TBtu for unit 1 and 0.91 lb/TBtu for unit 2. The EGUs demonstrated LEE status by showing that each of the units has a Hg PTE of less than 29 lb per year. Further, in LEE demonstration testing for the previous year (2022), Major Oak Power, LLC, found that the average Hg emissions rate for the 30-boiler operating day performance test was 0.86 lb/TBtu for unit 1 and 0.63 lb/TBtu for unit 2.

In the 2023 LEE demonstration compliance report, Twin Oaks unit 1 was described as a fluidized bed boiler that combusts lignite and is equipped with fluidized bed limestone (FBL) injection for SO_2 control, selective non-catalytic reduction (SNCR) for control of nitrogen oxides (NO_X), and a baghouse (FF) for PM control. In addition, unit 1 has an untreated activated carbon injection (UPAC) system as well as a brominated powdered activated carbon (BPAC) injection system for absorbing vapor phase Hg in the effluent upstream of the baghouse. Twin Oaks unit 2 is described in the same way.

Similarly, Red Hills units 1 and 2, located in Choctaw County, Mississippi,[71] also demonstrated 2021 annual emission rates while firing lignite from an adjacent mine of 1.33 lb/TBtu and 1.35 lb/TBtu, which are reasonably close to the proposed Hg emission standard of 1.2 lb/TBtu to demonstrate achievability. In 2022, average Hg emission rates for Red Hills unit 1 and unit 2, again while firing Mississippi lignite, were 1.73 lb/TBtu and 1.75 lb/TBtu, respectively. The EPA also notes that, as shown below in table 5, lignite mined in Mississippi has the highest average Hg content—as compared to lignites mined in Texas and North Dakota.

The performance of Twin Oaks units 1 and 2 and Red Hills Generating Facility units 1 and 2 clearly demonstrate the achievability of the proposed 1.2 lb/TBtu emission standard by lignite-fired EGUs. However, even if there were no lignite-fired EGUs that are meeting (or have demonstrated an ability to meet) the more stringent Hg emission standard, that would not mean that the more stringent emission standard was not achievable. Most Hg control technologies are ''dial up'' technologies—for example, sorbents or chemical additives have injection rates that can be ''dialed'' up or down to achieve a desired Hg emission rate. In response to the EPA's 2022 CAA section 114 information request, some responding owners/operators indicated that sorbent injection rates were set to maintain a Hg emission rate below the 4.0 lb/TBtu emission limit. In some instances, operators of EGUs reported that they were not injecting any Hg sorbent and were able to meet the less stringent emission standard. Most units that are permitted to meet a Hg emission standard of 4.0 lb/TBtu have no reason to ''over control'' since doing so by injecting more sorbent would increase their operating costs. So, it is unsurprising that many units that are permitted to fire lignite have reported Hg emission rates between 3.0 and 4.0 lb/TBtu.

While most lignite-fired EGUs have no reason to ''over control'' beyond their permitted emission standard of 4.0 lb/TBtu, Twin Oaks units 1 and 2 do have such motivation. As mentioned earlier, those sources have achieved LEE status for Hg (by demonstrating a Hg PTE of less than 29 lb/yr) and they must conduct annual performance tests to show that the units continue to qualify. According to calculations provided in their annual LEE certification, to maintain LEE status, the units could emit no more than 1.79 lb/TBtu and maintain a PTE of less than 29 lb/TBtu. So, the facilities are motivated to over control beyond 1.79 lb/TBtu (which, as described earlier in this preamble, they have consistently done).

Comment: To highlight the difference in the ability of lignite-fired and subbituminous-fired EGUs to control Hg, one commenter created a table to show a comparison between the Big Stone Plant (an EGU located in South Dakota firing subbituminous coal) and Coyote Station (an EGU located in North Dakota firing lignite). Additionally, the commenter included figures showing rolling 30-boiler operating day average Hg emission rates and the daily average ACI feed rates for Big Stone and Coyote EGUs for years 2021–2022. Their table showed that Big Stone and Coyote are similarly configured plants that utilize the same halogenated ACI for Hg control. The commenters said, however, that Coyote Station's average sorbent feed rate on a lb per million actual cubic feet (lb/MMacf) basis is more than three times higher than that for Big Stone, yet Coyote Station's average Hg emissions on a lb/TBtu basis are more than five times higher than Big Stone.

Response: The EPA agrees that the Big Stone and Coyote Station units referenced by the commenter are similarly sized and configured EGUs, with the Big Stone unit in South Dakota firing subbituminous coal and the Coyote Station unit in North Dakota firing lignite. However, there are several features of the respective units that can have an impact on the control of Hg. First, and perhaps the most significant, the Big Stone unit has a selective catalytic reduction (SCR) system installed for control of NOx. The presence of an SCR is known to enhance the control of Hg—especially in the presence of chemical additives. The Coyote Station EGU does not have an installed SCR. Further, both EGUs have a dry FGD scrubber and FF baghouse installed for SO_2/acid gas and fPM control. The average sulfur content of North Dakota lignite is approximately 2.5 times greater than that of Wyoming subbituminous coal. However, the average SO_2 emissions from the Coyote Station EGU (0.89 lb/MMBtu) were approximately 10 times higher than the SO_2 emissions from the Big Stone EGU (0.09 lb/MMBtu). The Big Stone dry scrubber/FF was installed in 2015; while the dry scrubber/FF at Coyote Station was installed in 1981—approximately 31 years earlier. So, considering the presence of an SCR—which is known to enhance Hg control—and newer and better performing downstream controls, it is unsurprising that there are differences in the control of Hg at the two EGUs. In addition, since the Coyote Station has been subject to a Hg emission standard of 4.0 lb/TBtu, there would be no reason for the operators to further optimize its control system to achieve a lower emission rate. And, as numerous commenters noted, the Hg content of North Dakota is higher than that of Wyoming subbituminous coal.

Comment: Some commenters claimed that the EPA has not adequately justified a reversal in the previous policy to establish a separate subcategory for lignite-fired EGUs.

[70] See page 1–1 of the 2023 Compliance Reports for Twin Oaks 1 and 2 available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[71] Choctaw Generation LP leases and operates the Red Hills Power Plant. The plant supplies electricity to the Tennessee Valley Authority (TVA) under a 30-year power purchase agreement. The lignite output from the adjacent mine is 100 percent dedicated to the power plant. *https://www.purenergyllc.com/projects/choctaw-generation-lp-red-hills-power-plant/#page-content.*

Response: In developing the 2012 Final MATS Rule, the EPA examined the EGUs in the top performing 12 percent of sources for which the Agency had Hg emissions data. In examining that data, the EPA observed that there were no lignite-fired EGUs among the top performing 12 percent of sources for Hg emissions. The EPA then determined that this indicated that there is a difference in the Hg emissions from lignite-fired EGUs when compared to the Hg emissions from EGUs firing other coal types (that were represented among the top performing 12 percent). That determination was not based on any unique property or characteristic of lignite—only on the observation that there were no lignite-fired EGUs among the best performing 12 percent of sources (for which the EPA had Hg emissions data). In fact, as noted in the preamble for the 2012 Final MATS Rule, the EPA ''believed at proposal that the boiler size was the cause of the different Hg emissions characteristics.'' See 77 FR 9378.

The EPA ultimately concluded that it is appropriate to continue to base the subcategory definition, at least in part, on whether the EGUs were ''designed to burn and, in fact, did burn low rank-virgin coal'' (*i.e.,* lignite), but that it is not appropriate to continue to use the boiler size criteria (*i.e.,* the height-to-depth ratio). However, the EPA ultimately finalized the ''unit designed for low rank virgin coal'' subcategory based on the characteristics of the EGU—not on the properties of the fuel. ''We are finalizing that the EGU is considered to be in the ''unit designed for low rank virgin coal'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is designed to burn and is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.'' See 77 FR 9369.

While, in the 2012 MATS Final Rule, the EPA based the lignite-fired EGU subcategory on the design and operation of the EGUs, the EPA did not attribute the observed differences in Hg emissions to any unique characteristic(s) of lignite. As the EPA clearly noted in the 2023 Proposal, there are, in fact, characteristics of lignite that make the control of Hg more challenging. These include the low natural halogen content, the high alkalinity of the fly ash, the sulfur content, the relatively higher Hg content, and the relatively higher variability of Hg content. However, as the EPA has explained, these characteristics that make the control of Hg more challenging are also found in non-lignite fuels. Subbituminous coals also have low natural halogen content and high fly ash alkalinity. Eastern and central bituminous coals also have high sulfur content. Bituminous and anthracitic waste coals (coal refuse) have very high and variable Hg content. EGUs firing any of these non-lignite coals have been subject to—and have demonstrated compliance with—the more stringent Hg emission standard of 1.2 lb/TBtu.

The EPA has found it appropriate to reverse the previous policy because the decision to subcategorize ''units designed for low rank virgin coal'' in the 2012 MATS Final Rule was based a determination that there were differences in Hg emissions from lignite-fired EGUs as compared to EGUs firing non-lignite coals. That perceived difference was based on an observation that there were no lignite-fired EGUs in the top performing 12 percent of EGUs for which the Agency had Hg emissions data and on an assumption that the perceived difference in emissions was somehow related to the design and operation of the EGU. The EPA is unaware of any distinguishing features of EGUs that were designed to burn lignite that would impact the emissions of Hg. Further, the EPA does not now view the fact that there were no lignite-fired EGUs in the population of the best-performing 12 percent of EGUs for which the Agency had Hg emissions data to represent a ''difference in emissions.''

But, on re-examination of the data, the EPA has concluded that the Hg emissions from the 2010 ICR for the lignite-fired EGUs were not clearly distinctive from the Hg emissions from EGUs firing non-lignite coal. In setting the emission standards for the 2012 MATS Final Rule, the EPA had available and useable Hg emissions data from nearly 400 coal-fired EGUs (out of the 1,091 total coal-fired EGUs operating at that time). However, the EPA only had available and useable data from nine lignite-fired EGUs with reported floor Hg emissions ranging from 1.0 to 10.9 lb/TBtu. But these were not outlier emission rates. EGUs firing bituminous coal reported Hg emissions as high as 30.0 lb/TBtu; and those firing subbituminous coal reported Hg emissions as high as 9.2 lb/TBtu.

D. What is the rationale for our final approach and decisions for the lignite-fired EGU Hg standard?

In the 2023 Proposal, the EPA proposed to determine that there are developments in available control technologies and methods of operation that would allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu—the same Hg emission standard that must be met by coal-fired EGUs firing non-lignite coals (*e.g.,* anthracite, bituminous coal, subbituminous coal, coal refuse, *etc.*). After consideration of public comments received on the proposed revision of the Hg emission standard, the EPA continues to find that the evidence supports that there are commercially available control technologies and improved methods of operation that allow lignite-fired EGUs to meet the more stringent Hg emission standard that the EPA proposed. As noted above, lignite-fired EGUs also comprise some of the largest sources of Hg emissions within this source category and are responsible for a disproportionate share of Hg emissions relative to their generation. While previous EPA assessments have shown that current modeled exposures [of Hg] are well below the reference dose (RfD), we conclude that further reductions of Hg emissions from lignite-fired EGUs covered in this final action should further reduce exposures including for the subsistence fisher sub-population. This anticipated exposure is of particular importance to children, infants, and the developing fetus given the developmental neurotoxicity of Hg. Therefore, in this final action, the EPA is revising the Hg emission standard for lignite-fired EGUs from the 4.0 lb/TBtu standard that was finalized in the 2012 MATS Final Rule to the more stringent emission standard of 1.2 lb/TBtu, as proposed. The rationale for the Agency's final determination is provided below.

In this final rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the Hg emission standard for lignite-fired EGUs. As discussed in section II.D. above, the 2020 Technology Review did not evaluate the current performance of emission reduction control equipment and strategies at existing lignite-fired EGUs. Nor did the 2020 Technology Review specifically address the discrepancy between Hg emitted from lignite-fired EGUs and non-lignite coal-fired EGUs or consider the improved performance of injected sorbents or chemical additives, or the development of SO_3-tolerant sorbents. Based on the EPA's review in this rulemaking which considered such information, the Agency determined that there are available control technologies that allow EGUs firing lignite to achieve an emission standard of 1.2 lb/TBtu, consistent with the Hg emission standard required for non-lignite coal-fired EGUs, which the EPA is finalizing pursuant to its CAA section 112(d)(6) authority.

1. Mercury Content of Lignite

For analyses supporting the proposal, the EPA assumed ''Hg Inlet'' levels (*i.e.,* Hg concentration in inlet fuel) that are consistent with those assumed in the Agency's power sector model (IPM) and then adjusted accordingly to reflect the 2021 fuel blend for each unit. Several commenters indicated that the Hg content of lignite fuels is much higher and has greater variability than the EPA assumed.

To support the development of the NESHAP for the Coal- and Oil-Fired EGU source category, the Agency conducted a 2-year data collection effort which was initiated in 1998 and completed in 2000 (1998 ICR). The ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly owned utility companies, federal power agencies, rural electric cooperatives, and investor-owned utility generating companies; (2) obtaining accurate information on the amount of Hg contained in the as-fired coal used by each electric utility steam generating unit with a capacity greater than 25 MW electric, as well as accurate information on the total amount of coal burned by each such unit; and (3) obtaining data by coal sampling and stack testing at selected units to characterize Hg reductions from representative unit configurations.

The ICR captured the origin of the coal burned, and thus provided a pathway for linking emission properties to coal basins. The 1998–2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, Hg content, ash content, chlorine content, and other characteristics of coal burned at coal-fired utility boilers greater than 25 MW.

Annual fuel characteristics and delivery data reported on EIA form 923 also provide continual data points on coal heat content, sulfur content, and geographic origin, which are used as a check against characteristics initially identified through the 1998 ICR.

For this final rule, the EPA re-evaluated the 1998 ICR data.[72] Specifically, the EPA evaluated the coal Hg data to characterize the Hg content of lignite, which is mined in North Dakota, Texas, and Mississippi, and to characterize by seam and by coal delivered to a specific plant.[73] The results are presented as a range of Hg content of the lignites as well as the mean and median Hg content. The EPA also compared the fuel characteristics of lignites mined in North Dakota, Texas, and Mississippi against coals mined in Wyoming (subbituminous coal), Pennsylvania (mostly upper Appalachian bituminous coal), and Kentucky (mostly lower Appalachian bituminous coal). The Agency also included in the re-evaluation, coal analyses that were submitted in public comments by North American Coal (NA Coal). In addition to the Hg content, the analysis included the heating value and the sulfur, chlorine, and ash content for each coal that is characterized.

The analysis showed that lignite mined in North Dakota had a mean Hg content of 9.7 lb/TBtu, a median Hg content of 8.5 lb/TBtu, and a Hg content range of 2.2 to 62.1 lb/TBtu. Other characteristics of North Dakota lignite include an average heating value (dry basis) of 10,573 Btu/lb, an average sulfur content of 1.19 percent, an average ash content of 13.5 percent, and an average chlorine content of 133 parts per million (ppm). In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in North Dakota to 9.7 lb/TBtu versus the 7.81 lb/TBtu assumed in the 2023 Proposal.

Similarly, the analysis showed that lignite mined in Texas had a mean and median Hg content of 25.0 lb/TBtu and 23.8 lb/TBtu, respectively, and a Hg content range from 0.7 to 92.0 lb/TBtu. Other characteristics include an average heating value (dry basis) of 9,487 Btu/lb, an average sulfur content of 1.42 percent, an average ash content of 24.6 percent, and an average chlorine content of 233 ppm. In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in Texas to 25.0 lb/TBtu versus the range of 14.65 to 14.88 lb/TBtu that was assumed for the 2023 Proposal.

Lignite mined in Mississippi had the highest mean Hg content at 34.3 lb/TBtu and the second highest median Hg emissions rate, 30.1 lb/TBtu. The Hg content ranged from 3.6 to 91.2 lb/TBtu. Lignite from Mississippi had an average heating value (dry basis) of 5,049 Btu/lb and a sulfur content of 0.58 percent. In response to comments submitted on the 2023 Proposal, for analyses supporting this final action, the EPA assumed a Hg content of 34.3 lb/TBtu for lignite mined in Mississippi versus the 12.44 lb/TBtu assumed for the proposal.

The EPA 1998 ICR dataset did not contain information on lignite from Mississippi, which resulted in a smaller number of available data points (227 in Mississippi lignite versus 864 for North Dakota lignite and 943 for Texas lignite). Table 5 of this document more fully presents the characteristics of lignite from North Dakota, Texas, and Mississippi.

[72] Technical Support Document ''*1998 ICR Coal Data Analysis Summary of Findings*'' available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[73] In 2022, over 99 percent of all lignite was mined in North Dakota (56.2 percent), Texas (35.9 percent), and Mississippi (7.1 percent). Small amounts (less than 1 percent) of lignite were also mined in Louisiana and Montana. See Table 6. ''Coal Production and Number of Mines by State and Coal Rank'' from EIA Annual Coal Report, available at *https://www.eia.gov/coal/annual/.*

Table 5. Characteristics of Lignite mined in North Dakota, Texas, and Mississippi from the EPA 1998 ICR Dataset

	North Dakota	Texas	Mississippi
Number of data points	864	943	227
Range of Hg content (lb/TBtu)	2.2 – 62.1	0.7 – 92.0	3.6 – 91.2
Mean Hg content (lb/TBtu)	9.7	25.0	34.3
Median Hg content (lb/TBtu)	8.5	23.8	30.1
Heating value average (Btu/lb, dry)	10,573	9,486	5,049
Sulfur content average (%, dry)	1.12	1.42	0.58
Ash content average (%, dry)	13.54	24.60	N/A
Chlorine content average (ppm, dry)	133	232	N/A

Coals mined in Kentucky, Pennsylvania, and Wyoming were also analyzed for comparison. The types of coal (all non-lignite) included bituminous, bituminous-high sulfur, bituminous-low sulfur, subbituminous, anthracite, waste anthracite, waste bituminous, and petroleum coke. Bituminous coal accounted for 92 percent of the data points from Kentucky and 75 percent of the data points from Pennsylvania. Subbituminous coal accounted for 96 percent of the data points from Wyoming.

Bituminous coals from Kentucky had a mean Hg emissions content of 7.2 lb/TBtu (ranging from 0.7 to 47.4 lb/TBtu), an average heating value (dry basis) of 13,216 Btu/lb, an average sulfur content of 1.43 percent, an average ash content of 10.69 percent, and an average chlorine content of 1,086 ppm.

Bituminous coals from Pennsylvania had a mean Hg emissions rate of 14.5 lb/TBtu (ranging from 0.1 to 86.7 lb/TBtu), an average heating value (dry basis) of 13,635 Btu/lb, an average sulfur content of 1.88 percent, an average ash content of 10.56 percent, and an average chlorine content of 1,050 ppm.

Subbituminous coals from Wyoming had a mean Hg rate of 5.8 lb/TBtu, an average heating value (dry basis) of 12,008 Btu/lb, an average sulfur content of 0.44 percent, an average ash content of 7.19 percent, and an average chlorine content of 127 ppm. Table 6 of this document shows the characteristics of bituminous coal from Kentucky and Pennsylvania and subbituminous coal from Wyoming.

Table 6. Characteristics of Bituminous and Subbituminous Coals mined in Kentucky, Pennsylvania, and Wyoming from the EPA 1998 ICR Dataset

	Kentucky (Bituminous)	Pennsylvania (Bituminous)	Wyoming (Subbituminous)
Number of data points	5,340	3,072	6,467
Range of Hg content (lb/TBtu)	0.7 – 47.4	0.1 – 86.7	0.7 – 40.7
Mean Hg content (lb/TBtu)	7.2	14.5	5.8
Median Hg content (lb/TBtu)	6.7	9.7	2.4
Heating value average (Btu/lb, dry)	13,216	13,635	12,008
Sulfur content average (%, dry)	1.43	1.88	0.44
Ash content average (%, dry)	10.69	10.56	7.19
Chlorine content average (ppm, dry)	1,086	1,050	127

Several commenters claimed that one of the factors that contributes to the challenge of controlling Hg emissions from EGUs firing lignite is the variability of the Hg content in lignite. However, as can be seen in table 5 and table 6 of this document, all coal types examined by the EPA contain a variable content of Hg. The compliance demonstration requirements in the 2012 MATS Final Rule were designed to accommodate the variability of Hg in coal by requiring compliance with the respective Hg emission standards over a 30-operating-day rolling average period. When examining the Hg emissions for EGUs firing on the various coal types (including those firing Wyoming subbituminous coal, which has the lowest mean and median Hg content and the narrowest range of Hg content), daily emissions often exceed the applicable emission standard (sometimes considerably). However, averaging emissions over a rolling 30-operating-day period effectively dampens the impacts of fuel Hg content variability. For example, in figure 1 (a graph) of this document, the 2022 Hg emissions from Dave Johnston unit BW41, a unit firing subbituminous coal, are shown. The graph shows both the daily Hg emissions and the 30-operating-day rolling average Hg emissions. As can be seen in the graph, the daily Hg emissions very often exceed the 1.2 lb/TBtu emission rate; however, the 30-operating-day rolling average is consistently below the emission limit (the annual average emission rate is 0.9 lb/TBtu).

BILLING CODE 6560–50–P

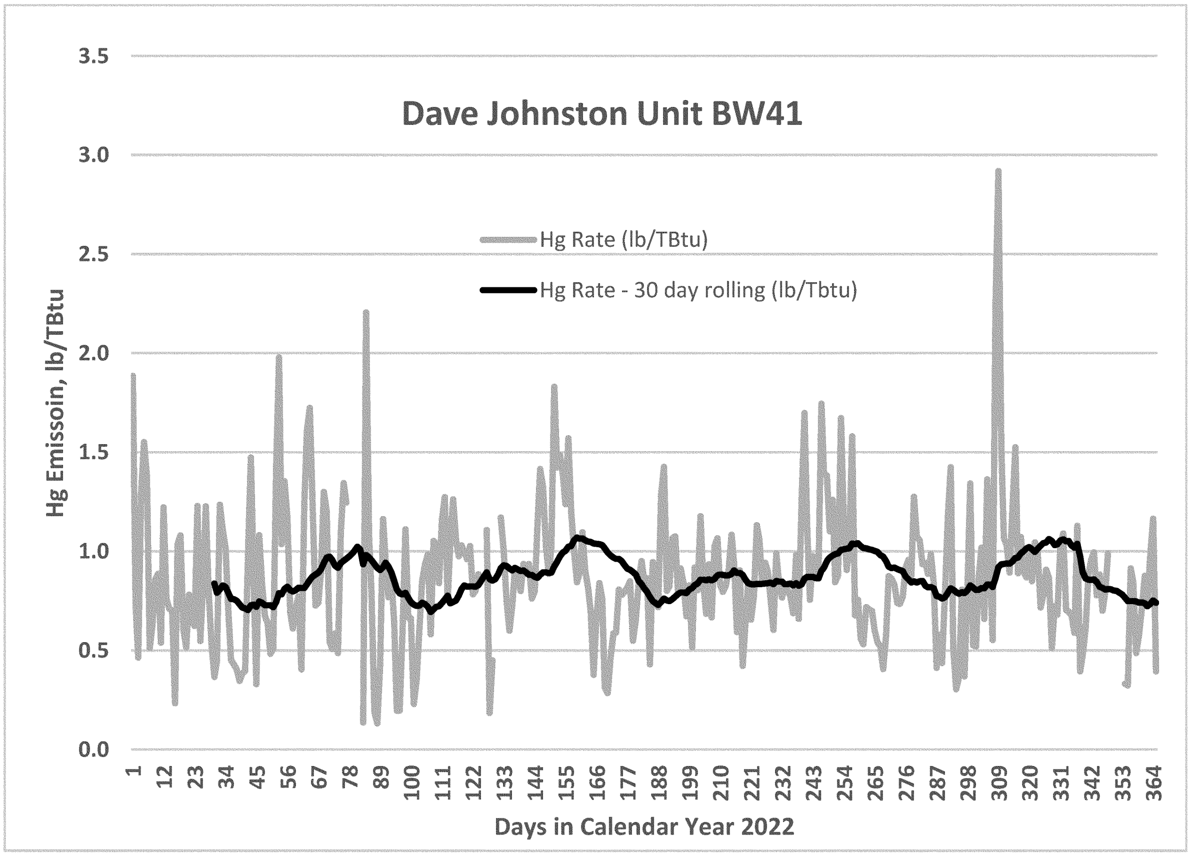


Figure 1. 2022 Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu)

From Dave Johnston Unit BW41, a subbituminous-fired EGU in Wyoming.

A similar effect can be seen with the 2022 daily and 30-operating-day rolling average Hg emissions from Leland Olds unit 1, an EGU firing North Dakota lignite, shown in figure 2 of this document.

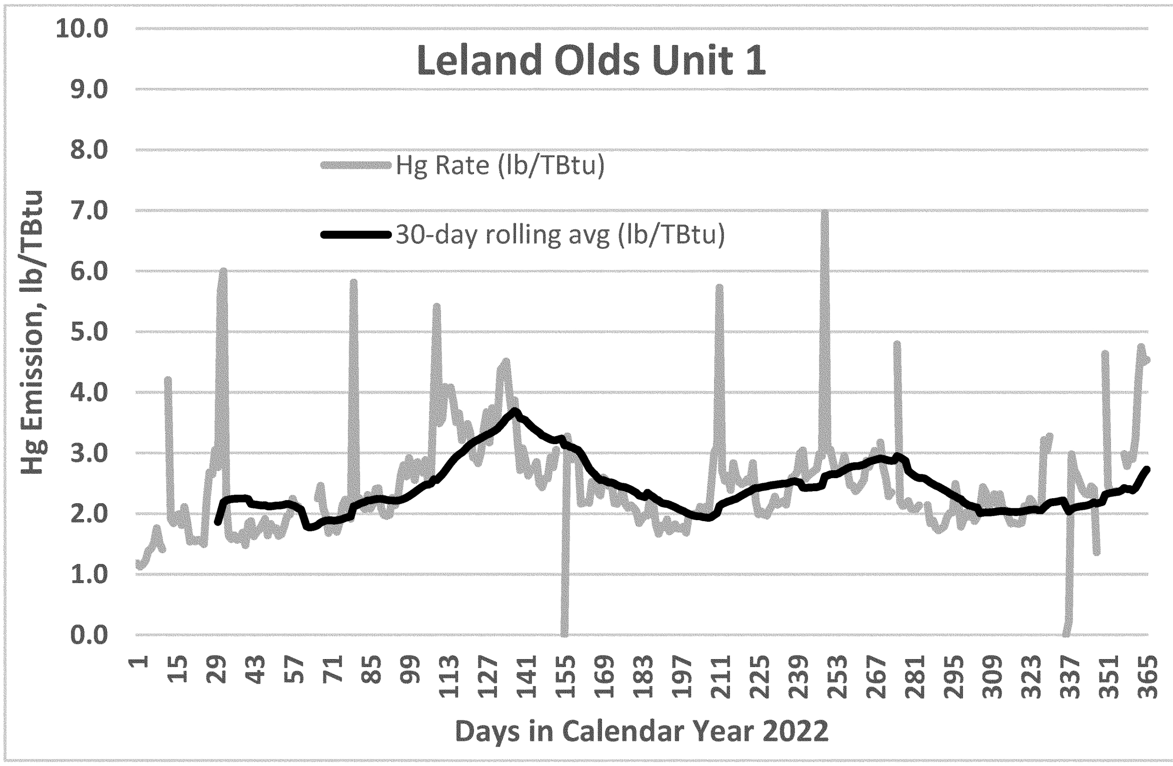


Figure 2. Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu) from Leland Olds Unit 1, lignite-fired EGU in North Dakota.

BILLING CODE 6560–50–C

As with the EGU firing subbituminous coal, the daily Hg emissions very often exceed the emission limit (in this case 4.0 lb/TBtu); however, the 30-operating-day rolling average is consistently below the applicable emission limit (the 2022 annual average emission rate for Leland Olds unit 1 is 2.3 lb/TBtu).

2. The Impact of Halogen Content of Lignite on Hg Control

In the 2023 Proposal, the EPA explained that during combustion of coal, the Hg contained in the coal is volatilized and converted to Hg^0 vapor in the high-temperature regions of the boiler. Hg^0 vapor is difficult to capture because it is typically nonreactive and insoluble in aqueous solutions. However, under certain conditions, the Hg^0 vapor in the flue gas can be oxidized to divalent Hg (Hg^{2+}). The Hg^{2+} can bind to the surface of solid particles (*e.g.,* fly ash, injected sorbents) in the flue gas stream, often referred to as ''particulate bound Hg'' (Hg_p) and be removed in a downstream PM control device. Certain oxidized Hg compounds that are water soluble may be further removed in a downstream wet scrubber. The presence of chlorine in gas-phase equilibrium favors the formation of mercuric chloride ($HgCl_2$) at flue gas cleaning temperatures. However, Hg^0 oxidation reactions are kinetically limited as the flue gas cools, and as a result Hg may enter the flue gas cleaning device(s) as a mixture of Hg^0, Hg^{2+} compounds, and Hg_p.

This partitioning into various species of Hg has considerable influence on selection of Hg control approaches. In tables 5 and 6 of this document, the chlorine content of bituminous coals mined in Kentucky and Pennsylvania averaged 1,086 ppm and 1,050 ppm, respectively. In comparison, the average chlorine content of Wyoming subbituminous coal is 127 ppm; while the chlorine contents of lignite mined in North Dakota and Texas are 133 ppm and 232 ppm, respectively. In general, because of the presence of higher amounts of halogen (especially chlorine) in bituminous coals, most of the Hg in the flue gas from bituminous coal-fired boilers is in the form of Hg^{2+} compounds, typically $HgCl_2$, and is more easily captured in downstream control equipment. Conversely, both subbituminous coal and lignite have lower natural halogen content compared to that of bituminous coals, and the Hg in the flue gas from boilers firing those fuels tends to be in the form of Hg^0 and is more challenging to control in downstream control equipment.

While some bituminous coal-fired EGUs require the use of additional Hg-specific control technology, such as injection of a sorbent or chemical additive, to supplement the control that these units already achieve from criteria pollutant control equipment, these Hg-specific control technologies are often required as part of the Hg emission reduction strategy at EGUs that are firing subbituminous coal or lignite. As described above, the Hg in the flue gas for EGUs firing subbituminous coal or lignite tends to be in the nonreactive Hg^0 vapor phase due to lack of available free halogen to promote the oxidation reaction. To alleviate this challenge, activated carbon and other sorbent providers and control technology vendors have developed methods to introduce halogen into the flue gas to improve the control of Hg emissions from EGUs firing subbituminous coal and lignite. This is primarily through the injection of pre-halogenated (often pre-brominated) activated carbon sorbents or through the injections of halogen-containing chemical additives along with conventional sorbents. In the

2022 CAA section 114 information collection, almost all the lignite-fired units reported use of some sort of halogen additive or injection as part of their Hg control strategy by using refined coal (which typically has added halogen), bromide or chloride chemical additives, pre-halogenated sorbents, and/or oxidizing agents. Again, low chlorine content in the fuel is a challenge that is faced by EGUs firing either subbituminous coals or lignite, and EGUs firing subbituminous coal have been subject to a Hg emission standard of 1.2 lb/TBtu since the MATS rule was finalized in 2012.

3. The Impact of SO_3 on Hg Control

Some commenters noted that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. As shown in table 5 and table 6 of this document, while the halogen content of subbituminous coal and lignite is similar, the average sulfur content of lignite is more like that of bituminous coal mined in Kentucky and Pennsylvania.

During combustion, most of the sulfur in coal is oxidized into SO_2, and only a small portion is further oxidized to SO_3 in the boiler. In response to environmental requirements, many EGUs have installed SCR systems for NO_X control and FGD systems for SO_2 control. One potential consequence of an SCR retrofit is an increase in the amount of SO_3 in the flue gas downstream of the SCR due to catalytic oxidation of SO_2. Fly ash and condensed SO_3 are the major components of flue gas that contribute to the opacity of a coal plant's stack emissions and the potential to create a visible sulfuric acid ''blue plume.'' In addition, higher SO_3 levels can adversely affect many aspects of plant operation and performance, including corrosion of downstream equipment and fouling of the air preheater (APH). This is primarily an issue faced by EGUs firing bituminous coal. EGUs fueled by subbituminous coal and lignite do not typically have the same problem with blue plume formation. Of the EGUs that are designed to fire lignite, only Oak Grove units 1 and 2, located in Texas, have an installed SCR for NO_X control. Several lignite-fired EGUs utilize SNCR systems for NO_X control, which are less effective for NO_X control as compared to SCR systems. Several commenters claimed that SCR is not a viable NO_X control technology for EGUs firing North Dakota lignite because of catalyst fouling from the high sodium content of the fuel and resulting fly ash.

Coal fly ash is typically classified as acidic (pH less than 7.0), mildly alkaline (pH greater than 7.0 to 9.0), or strongly alkaline (pH greater than 9.0). The pH of the fly ash is usually determined by the calcium/sulfur ratio and the amount of halogen. The ash from bituminous coals tends to be acidic due to the relatively higher sulfur and halogen content and the glassy (nonreactive) nature of the calcium present in the ash. Conversely, the ash from subbituminous coals and lignite tends to be more alkaline due to the lower amounts of sulfur and halogen and a more alkaline and reactive (non-glassy) form of calcium—and, as noted by commenters—the presence of sodium compounds in the ash. The natural alkalinity of the subbituminous and lignite fly ash may effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0. However, the natural alkalinity also helps to minimize the impact of SO_3, because a common control strategy for SO_3 is the injection of alkaline sorbents (dry sorbent injection, DSI).

Still, as commenters correctly noted, the presence of SO_3 in the flue gas stream is also known to negatively impact the effectiveness of sorbent injection for Hg control. This impact has been known for some time, and control technology researchers and vendors have developed effective controls and strategies to minimize the impact of SO_3.[74] As noted above, coal-fired EGUs utilizing bituminous coal—which also experience significant rates of SO_3 formation in the flue gas stream—have also successfully demonstrated the application of Hg control technologies to meet a standard of 1.2 lb/TBtu.

The AECOM patented SBS Injection™ (''sodium-based solution'') technology has been developed for control of SO_3, and co-control of Hg has also been demonstrated. A sodium-based solution is injected into the flue gas, typically ahead of the APH or, if present, the SCR. By removing SO_3 prior to these devices, many of the adverse effects of SO_3 can be successfully mitigated. AECOM has more recently introduced their patented HBS Injection™ technology for effective Hg oxidation and control.[75] This new process injects halogen salt solutions into the flue gas, which react in-situ to form halogen species that effectively oxidize Hg. The HBS Injection™ can be co-injected with the SBS Injection™ for effective SO_3 control and Hg oxidation/control.

Other vendors also offer technologies to mitigate the impact of SO_3 on Hg control from coal combustion flue gas streams. For example, Calgon Carbon offers their ''sulfur tolerant'' Fluepac ST, which is a brominated powdered activated carbon specially formulated to enhance Hg capture in flue gas treatment applications with elevated levels of SO_3.[76] In testing in a bituminous coal combustion flue gas stream containing greater than 10 ppm SO_3, the Fluepac ST was able to achieve greater than 90 percent Hg control at injection rates of a third or less as compared to injection rates using the standard brominated sorbent.

Babcock & Wilcox (B&W) offers dry sorbent injection systems that remove SO_3 before the point of activated carbon sorbent injection to mitigate the impact of SO_3.[77] Midwest Energy Emissions Corporation (ME_2C) offers ''high-grade sorbent enhancement additives—injected into the boiler in minimal amounts'' that work in conjunction with proprietary sorbent products to ensure maximum Hg capture. ME_2C claims that their Hg control additives and proprietary sorbent products are ''high-sulfur-tolerant and SO_3-tolerant sorbents.''[78]

Cabot Norit Activated Carbon is the largest producer of powdered activated carbon worldwide.[79] Cabot Norit offers different grades of their DARCO® powdered activated carbon (PAC) for Hg removal at power plants. These grades include non-impregnated PAC which are ideal when most of the Hg is in the oxidized state; impregnated PAC for removing oxidized and Hg^0 from flue gas; special impregnated PAC used in conjunction with DSI systems (for control of acid gases); and special impregnated ''sulfur resistant'' PAC for flue gases that contains higher concentrations of acidic gases like SO_3.

[74] The mention of specific products by name does not imply endorsement by the EPA. The EPA does not endorse or promote any particular control technology. The EPA mentions specific product names here to emphasize the broad range of products and vendors offering sulfur tolerant Hg control technologies.

[75] *https://www.aecom.com/wp-content/uploads/2019/07/10_EUEC_P_PT_Brochure_HBS_InjectionTechnology_20160226_singles.pdf.*

[76] *https://www.calgoncarbon.com/app/uploads/DS-FLUEST15-EIN-E1.pdf.*

[77] *https://www.babcock.com/assets/PDF-Downloads/Emissions-Control/E101-3200-Mercury-and-HAPs-Emissions-Control-Brochure-Babcock-Wilcox.pdf.*

[78] ME2C 2016 Corporate Brochure, available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[79] *https://norit.com/application/power-steel-cement/power-plants.*

Similarly, ADA–ES offers FastPAC™ Platinum 80,[80] an activated carbon sorbent that was specifically engineered for SO_3 tolerance and for use in applications where SO_3 levels are high. So, owner/operators of lignite-fired EGUs can choose from a range of technologies and technology providers that offer Hg control options in the presence of SO_3. The EPA also notes that SO_3 is more often an issue with EGUs firing eastern bituminous coal—as those coals typically have higher sulfur content and lower ash alkalinity. Those bituminous coal-fired EGUs are subject to—and have demonstrated compliance with—an emission standard of 1.2 lb/TBtu.

[80] *https://www.advancedemissionssolutions.com/ADES-Investors/ada-products-and-services/default.aspx.*

4. Cost Considerations for the More Stringent Hg Emission Standard

From the 2022 CAA section 114 information survey, most lignite-fired EGUs utilized a control strategy that included sorbent injection coupled with chemical additives (usually halogens). In the beyond-the-floor analysis in the 2012 MATS Final Rule, we noted that the results from various demonstration projects suggested that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbents at an injection rate of 2.0 lb/MMacf (*i.e.,* 2.0 pounds of sorbent injected per million actual cubic feet of flue gas) for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. As shown in table 7 of this document, all units (in 2022) would have needed to control their Hg emissions to 95 percent or less to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the final, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule.

BILLING CODE 6560–50–P

Table 7. Measured Hg Emissions and Estimated Control Performance of Lignite-Fired EGUs in 2022

EGU	Estimated 2022 Hg Inlet[81] (lb/TBtu)	Estimated Hg Control (%) at 4.0 lb/TBtu	Estimated Hg Control (%) at 1.2 lb/TBtu	2022 Measured Hg Emissions (lb/TBtu)	Estimated 2022 Hg Control (%)
North Dakota EGUs					
Antelope Valley 1	11.2	64.4	89.3	3.03	73.0
Antelope Valley 2	11.2	64.4	89.3	3.00	73.3
Coal Creek 1	9.7	58.7	87.6	3.43	64.6
Coal Creek 2	9.7	58.7	87.6	3.87	60.1
Coyote 1	9.7	58.6	87.6	2.28	76.4
Leland Olds 1	11.3	64.5	87.6	2.34	79.3
Leland Olds 2	11.3	64.5	87.6	3.10	72.5
Milton R Young 1	9.7	58.6	87.6	3.02	68.8
Milton R Young 2	9.7	58.6	87.6	3.00	69.0
Spiritwood Station 1	9.2	56.5	87.0	2.14	76.8
Texas and Mississippi EGUs					
Limestone 1*	5.8	30.7	79.2	0.78	86.5
Limestone 2*	5.8	30.7	79.2	0.85	85.3
Major Oak Power 1	24.9	84.0	95.2	0.86	96.5
Major Oak Power 2	24.9	84.0	95.2	0.63	97.5
Martin Lake 1*	5.8	31.0	79.3	1.53	73.6
Martin Lake 2*	5.8	31.0	79.3	2.50	56.9
Martin Lake 3*	5.8	31.0	79.3	2.36	59.3
Oak Grove 1	24.8	83.9	95.2	2.53	89.8
Oak Grove 2	24.8	83.9	95.2	2.23	91.0
San Miguel 1	28.9	86.2	95.9	3.03	89.5
Red Hills 1	22.9	82.6	94.8	1.73	92.5
Red Hills 2	22.9	82.6	94.8	1.75	92.4

* These units, which are permitted to fire lignite, utilized primarily subbituminous coal in 2022.

BILLING CODE 6560–50–C

To determinethe cost effectiveness of that strategy, we calculated the cost per lb of Hg controlled for a model 800 MW lignite-fired EGU, as described in the 2024 Technical Memo. We calculated the cost of injecting brominated activated carbon sorbent at injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule (*i.e.,* 2.0 lb/MMacf and 3.0 lb/MMacf) and at a larger injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu. We also calculated the incremental cost to meet the more stringent emission rate of 1.2 lb/TBtu versus the cost to meet an emission rate of 4.0 lb/TBtu using non-brominated activated carbon sorbent at an emission rate of 2.5 lb/MMacf. For an 800 MW lignite-fired EGU, the cost effectiveness of using the brominated carbon sorbent at an injection rate of 3.0 lb/MMacf was $3,050 per lb of Hg removed while the incremental cost effectiveness was $10,895 per incremental lb of Hg removed at a brominated activated carbon injection rate of 3.0 lb/MMacf. The cost effectiveness of using the brominated carbon sorbent at an injection rate of 5.0 lb/MMacf was $5,083 per lb of Hg removed while the incremental cost effectiveness was $28,176 per incremental lb of Hg removed. The actual cost effectiveness is likely lower than either of these estimates as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (from the 2022 CAA section 114 information collection, the Oak Grove units were injecting less than 0.5 lb/MMacf) and is either well below or reasonably consistent with the cost effectiveness that the EPA has found to

[81] Estimated Hg inlet values are based on fuel use data from EIA Form 923 and assumed Hg content of coals as shown in Table 5 and Table 6 in this preamble.

be acceptable in previous rulemakings for Hg controls.[82]

In addition to cost effectiveness, the EPA finds that the revised Hg emission standard for lignite-fired units appropriately considers the costs of controls, both total costs and as a fraction of total revenues, along with other factors that the EPA analyzed pursuant to its CAA section 112(d)(6) authority. Similar to the revised fPM emission standard (as a surrogate for non-Hg HAP metals) discussed in section IV. of this preamble, the EPA anticipates that the total costs of controls (which consists of small annual incremental operating costs) to comply with the revised Hg emission standard will be a small fraction of the total revenues for the impacted lignite-fired units. The EPA expects that sources will be able to meet the revised emission standard using existing controls (*e.g.,* using existing sorbent injection equipment), and that significant additional capital investment is unlikely. If site-specific conditions necessitate minor capital improvements to the ACI control technology, it is important to note that any incremental capital would be small relative to ongoing sorbent costs accounted for in this analysis. Further, in addition to the EPA finding that costs are reasonable for the revised Hg standard for lignite-fired EGUs, the revised standard will also bring these higher emitting sources of Hg emission in line with Hg emission rates that are achieved by non-lignite-fired EGUs. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

Despite the known differences in the quality and composition of the various coal types, the EPA can find no compelling reasons why EGUs that are firing lignite cannot meet the same emission limit as EGUs that are firing other types of coal (*e.g.,* eastern and western bituminous coal, subbituminous coal, and anthracitic and bituminous waste coal). Each of the coal types/ranks has unique compositions and properties. Low halogen content in coal is known to make Hg capture more challenging. But, both lignites and subbituminous coals have low halogen content with higher alkaline content. Lignites tend to have average higher Hg content than subbituminous and bituminous coals—especially lignites mined in Mississippi and Texas. However, waste coals (anthracitic and bituminous coal refuse) tend to have the highest average Hg content. Lignites tend to have higher sulfur content than that of subbituminous coals and the sulfur in the coal can form SO_3 in the flue gas. This SO_3 is known to make Hg capture using sorbent injection more challenging. However, bituminous coals and waste coals have similar or higher levels of sulfur. The formation of SO_3 is more significant with these coals. Despite all the obstacles and challenges presented to EGUs firing non-lignite coals, all of those EGUs have been subject to the more stringent Hg emission limit of 1.2 lb/TBtu—and emit at or below that emission limit since the rule was fully implemented. Advanced, better performing Hg controls—including ''SO_3 tolerant'' sorbents—are available to allow lignite-fired EGUs to also emit at or below the more stringent Hg emission limit of 1.2 lb/TBtu. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

VI. What is the rationale for our other final decisions and amendments from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the other NESHAP requirements?

The EPA did not propose any changes to the organic HAP work practice standards, acid gas standards, continental liquid oil-fired EGU standards, non-continental liquid oil-fired EGUs, limited-use oil-fired EGU standards, or standards for IGCC EGUs. The EPA proposed to require that IGCC EGUs use PM CEMS for compliance demonstration with their fPM standard.

The EPA did note in the 2023 Proposal that there have been several recent temporary and localized increases in oil combustion at continental liquid oil-fired EGUs during periods of extreme weather conditions, such as the 2023 polar vortex in New England. As such, the EPA solicited comment on whether the current definition of the limited-use liquid oil-fired subcategory remains appropriate or if, given the increased reliance on oil-fired generation during periods of extreme weather, a period other than the current 24-month period or a different threshold would be more appropriate for the current definition. The EPA also solicited comment on the appropriateness of including new HAP standards for EGUs subject to the limited use liquid oil-fired subcategory, as well as on the means of demonstrating compliance with the new HAP standards.

B. How did the technology review change for the other NESHAP requirements?

The technology review for the organic HAP work practice standards, acid gas standards, and standards for oil-fired EGUs has not changed from the proposal.

The proposed technology review with respect to the use of PM CEMS for compliance demonstration by IGCC EGUs has changed due to comments received on the very low fPM emission rates and on technical challenges with certifying PM CEMS on IGCC EGUs. Therefore, the Agency is not finalizing the required use of PM CEMS for compliance demonstration with the fPM emission standard at IGCC EGUs.

C. What key comments did we receive on the other NESHAP requirements, and what are our responses?

Comment: Commenters urged the EPA to retain the current definition of the limited-use liquid oil-fired subcategory and not to impose new HAP standards on EGUs in this subcategory, given that there are already limits on the amount of fuel oil that can be burned. Commenters noted that the Agency has not identified any justification for the costs required for implementation and compliance with new HAP standards for limited-use liquid oil-fired EGUs. Some commenters alleged that any changes to the existing HAP standards for EGUs in the limited-use liquid oil-fired subcategory may complicate reliability management during cold winter spells or other extreme weather events.

Response: The Agency did not propose changes to the limited-use liquid oil-fired EGU subcategory or to the requirements for such units. To evaluate the potential HAP emission impact of liquid oil-fired EGUs[83] during extreme weather events, the Agency reviewed the 2022 fPM emissions of 11 liquid oil-fired EGUs in the Northeast U.S. that were operated during December 2022 Winter Storm Elliot, as described in the 2024 Technical Memo. The review found that total non-Hg HAP metal emissions during 2022 from the 11 oil-fired EGUs in New England were very small—approximately 70 times lower than the non-Hg HAP metal emissions estimated from oil-fired units

[82] For example, the EPA proposed that $27,500 per lb of Hg removed was cost-effective for the Primary Copper RTR (87 FR 1616); and approximately $27,000 per lb of Hg ($2021) was found to be cost-effective in the beyond-the-floor analysis supporting the 2012 MATS Final Rule.

[83] Oil-fired EGUs burning residual fuel oil have generally higher emission rates of HAP compared to that from the use of other types of fuel.

in Puerto Rico, which were among the facilities with the highest (but acceptable) residual risk in the 2020 Residual Risk Review.[84] The EPA will continue to monitor the emissions from the dispatch of limited-use liquid oil-fired EGUs—especially during extreme weather events.

In addition, the Agency reviewed the performance of PM CEMS for compliance demonstration at oil-fired EGUs. Given the higher emission rates and limits from this subcategory of EGUs, the Agency did not find any of the correlation issues with the use of PM CEMS with oil-fired EGUs similar to those that were discussed earlier for coal-fired EGUs. Moreover, the benefits of PM CEMS use that were described earlier (*i.e.,* emissions transparency, operational feedback, *etc.*) translate well to oil-fired EGUs; therefore, the EPA is finalizing the requirement for oil-fired EGUs (excluding limited-use liquid oil-fired EGUs) to use PM CEMS for compliance demonstration, as proposed.

Comment: One commenter recommended that units involved with carbon capture and sequestration (CCS) projects retain the option to use stack testing for compliance demonstration. They said that PM emissions would be measured from the stack downstream of the carbon capture system (they specifically mentioned the carbon capture system being contemplated to be built to capture CO_2 emission from the Milton R. Young Station facility in North Dakota). The commenters said that PM CEMS correlation testing will cause operational impacts on the CCS operations due to operational changes or reduced control efficiencies that temporarily increase PM emissions for long time periods, resulting in CCS operations being adversely affected or even shut down for long periods.

Response: The Agency disagrees with the commenter's recommendation that units utilizing a carbon capture system should be able to continue to use periodic stack testing for compliance demonstration. At the present time, the many ways that CCS can be employed and deployed at coal-fired EGUs supports the use of PM CEMS for compliance purposes. For example, measures (such as a bypass stack) are available that would minimize the operational impacts on the carbon capture system and would allow for proper PM CEMS correlations. Furthermore, the Agency finds that the increased transparency and the improved ability to detect and correct potential control or operational problems offered by PM CEMS, as well as the greater assurance of continuous compliance, outweigh the minor operational impacts potentially experienced. To the extent that a specific coal- or oil-fired EGU utilizing CCS wishes to use an alternative test method for compliance demonstration purposes, its owner or operator may submit a request to the Administrator under the provisions of 40 CFR 63.7(f).

D. What is the rationale for our final approach and decisions regarding the other NESHAP requirements?

The Agency did not receive comments that led to any changes in the outcome of the technology review for other NESHAP requirements as presented in the 2023 Proposal. The Agency did not propose any changes for the current requirements for organic HAP work practice standards, acid gas standards, or standards for oil-fired EGUs and therefore no changes are being finalized.

The EPA is aware of two existing IGCC facilities that meet the definition of an IGCC EGU. The Edwardsport Power Station, located in Knox County, Indiana, includes two IGCC EGUs that had 2021 average capacity factors of approximately 85 percent and 67 percent. These EGUs have LEE qualification for PM, with most current test results of 0.0007 and 0.0003 lb/MMBtu, respectively. The Polk Power Station, located in Polk County, Florida, had a 2021 average capacity factor of approximately 70 percent but burned only natural gas in 2021 (*i.e.,* operating essentially as a natural gas combined cycle turbine EGU). Before this EGU switched to pipeline quality natural gas as a fuel, it qualified for PM LEE status in 2018; to the extent that the EGU again operates as an IGCC, it could continue to claim PM LEE status. While this subcategory has a less stringent fPM standard of 0.040 lb/MMBtu (as compared to that of coal-fired EGUs), recent compliance data indicate fPM emissions well below the most stringent standard option of 0.006 lb/MMBtu that was evaluated for coal-fired EGUs.

The EPA is not finalizing the required use of PM CEMS for compliance demonstration for IGCC EGUs due to technical limitations expressed by commenters. For example, commenters noted that due to differences in stack design, the only possible installation space for a PM CEMS on an IGCC facility is on a stack with elevated grating, exposing the instrument to the elements, which would impact the sensitivity and accuracy of a PM CEMS. Additionally, there are no PM control devices at an IGCC unit available for de-tuning, which is necessary for establishing a correlation curve under PS–11. The EPA has considered these comments and agrees with these noted challenges to the use of PM CEMS at IGCC EGUs and, for those reasons, the EPA is not finalizing the proposed requirement for IGCCs to use PM CEMS for compliance demonstration, thus IGCCs will continue to demonstrate compliance via fPM emissions testing. As a result of comments we received on coal-fired run durations and our consideration on those comments, along with the low levels of reported emissions, the EPA determined that owners or operators of IGCCs will need to ensure each run has a minimum sample volume of 2 dscm or a minimum mass collection of 3 milligrams. In addition, IGCC EGUs will continue to be able to obtain and maintain PM LEE status.

VII. Startup Definition for the Coal- and Oil-Fired EGU Source Category

A. What did we propose for the Coal- and Oil-Fired EGU source category?

In the 2023 Proposal, the EPA proposed to remove the alternative work practice standards, *i.e.,* those contained in paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 from the rule based on a petition for reconsideration from environmental groups that was remanded to the EPA in *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020), and responding in part to a separate petition for reconsideration from environmental groups, that sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review.[85] The first option under paragraph (1) defines startup as either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose, including onsite use. In the second option, startup is defined as the period in which operation of an EGU is initiated for any purpose, and startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown

[84] See *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2019 Risk and Technology Review Proposed Rule* (Docket ID No. EPA–HQ–OAR–2018–0794–0014).

[85] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov.*

event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any purpose (including onsite use), or 4 hours after the EGU makes useful thermal energy for industrial, commercial, heating, or cooling purposes, whichever is earlier.

As described in the 2023 Proposal, the Agency proposed to remove paragraph (2) of the definition of ''startup'' as part of our obligation to address the remand on this issue. In addition, as the majority of EGUs currently rely on work practice standards under paragraph (1) of the definition of ''startup,'' we believe this change is achievable by all EGUs and would result in little to no additional expenditures, especially since the additional reporting and recordkeeping requirements associated with use of paragraph (2) would no longer apply. Lastly, the time period for engaging PM or non-Hg HAP metal controls after non-clean fuel use, as well as for full operation of PM or non-Hg HAP metal controls, is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

B. How did the startup provisions change for the Coal- and Oil-Fired EGU source category?

The EPA is finalizing the amendment to remove paragraph (2) from the definition of ''startup'' as proposed.

C. What key comments did we receive on the startup provisions, and what are our responses?

We received both supportive and adverse comments on the proposed removal of paragraph (2) of the definition of ''startup.'' The summarized comments and the EPA's responses are provided in the *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments* document. The most significant adverse comments and the EPA's responses are provided below.

Comment: Commenters recommended that the 4-hour startup definition should continue to be allowed as removing it for simplicity is not an adequate justification. They said the EPA is conflating the MACT standard-setting process with this RTR process. Although the EPA notes that the best performing 12 percent of sources do not need this alternative startup definition, commenters stated that this change is beyond the scope of the technology review. Commenters asserted that the EPA's determination that only eight EGUs are currently using that option is insufficient justification for eliminating the definition. Given that the 2023 Proposal did not identify any flaws with the current definition, the commenters stated that the EPA should explain why elimination of the 4-hour definition from MATS is appropriate when there are units currently relying on it. Commenters also stated that the EPA should consider providing reasonable exemptions for the EGUs that currently use that definition, thus gradually phasing out the definition without imposing any additional compliance burdens. The commenters also argued that with potentially lower fPM standards, more facilities may need the additional flexibility allowed by this definition of startup as their margin of compliance is reduced. They noted that startup or non-steady state operation is not conducive to CEMS accuracy and that it may create false reporting of emissions data biased either high or low depending on the actual conditions.

Commenters stated that several facilities are currently required to use the 4-hour startup definition per federal consent decrees or state agreements. They said such a scenario provides clear justification for a limited exemption, as MATS compliance should not result in an EGU violating its consent decree. Commenters noted other scenarios where state permits have special conditions with exemptions from emission limits during ramp-up or ramp-down periods. They said many facilities alleviate high initial emissions by using alternate fuels to begin the combustion process, which has been demonstrated as a Best Management Practice and to lower emissions. Commenters noted that the permit modification process, let alone any physical or operational modifications to the facility, could take significantly longer than the 180-day compliance deadline, depending on public comments, meetings, or contested hearing requests made during the permit process.

Commenters stated the startup definition paragraph (2) has seen limited use due to the additional reporting requirements that the EPA imposed on sources that chose to use the definition, which they believe are unnecessary and should be removed from the rule. The commenters said that the analysis the EPA conducted during the startup/shutdown reconsideration in response to *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020) showed that the definition was reasonable, and they argued that the definition may be needed if the EPA further reduces the limits, given the transitory nature of unit and control operation during these periods. Commenters also stated that the startup definition paragraph (2) is beneficial to units that require extended startups. They said including allowances for cold startup conditions could allow some EGUs to continue operation until more compliant generation is built, which would help facilitate a smooth transition to newer plants that meet the requirements without risking the reliability of the electric grid. Commenters also noted that some control devices, such as ESPs, may not be operating fully even when the plant begins producing electricity.

Commenters stated that the EPA should consider allowing the use of diluent cap values from 40 CFR part 75. As these are limited under MATS, commenters noted that startup and shutdown variations are more pronounced than if diluent caps were to be allowed. They said that with a lower emissions limitation, the diluent cap would mathematically correct for calculation inaccuracies inherent in emission rate calculation immediately following startup. Commenters stated that relative accuracy test audits (RATA) must be conducted at greater than 50 percent load under 40 CFR part 60 and at normal operating load under 40 CFR part 75. They said that it is not reasonable to require facilities to certify their CEMS, including PM CEMS, at greater than 50 percent capacity and use it for compliance at less than 50 percent capacity. Commenters stated that startups have constantly changing flow and temperatures that do not allow compliance tests to be conducted during these periods.

Response: The Agency disagrees with the commenters who suggest that the 4-hour startup duration should be retained. As mentioned in the 2023 Proposal (88 FR 24885), owners or operators of coal- and oil-fired EGUs that generated over 98 percent of electricity in 2022 have made the requisite adjustments, whether through greater clean fuel capacity, better tuned equipment, better trained staff, a more efficient and/or better design structure, or a combination of factors, to be able to meet the requirements of paragraph (1) of the startup definition. This ability points out an improvement in operation that all EGUs should be able to meet at little to no additional expenditure, since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the startup definition were more expensive than the requirements of paragraph (1) of the definition. As mentioned with respect to gathering experience with PM CEMS, the Agency believes owners or operators of the 8 EGUs relying on the 4-hour startup period can build on their startup experience gained since finalization of the 2012 MATS Final Rule, along with the experience shared by some of the other EGUs that have been able to conform with startup definition paragraph (1), as well as the experience to be obtained in the period yet remaining before compliance is required; such experience could prove key to aiding source owners or operators in their shift from reliance on startup definition paragraph (2) to startup definition paragraph (1). Should EGU owners or operators find that their attempts to rely on startup definition (1) are unsuccessful after application of that experience, they may request of the Administrator the ability to use an alternate non-opacity standard, as described in the NESHAP general provisions at 40 CFR 63.6(g). Before the Administrator's approval can be granted, the EGU owner or operator's request must appear in the **Federal Register** for the opportunity for notice and comment by the public, as required in 40 CFR 63.6(g)(1).

Regarding consent decrees or state agreements for requirements other than those contained in this rule, while the rule lacks the ability to revise such agreements, the EPA recommends that EGU owners or operators contact the other parties to see what, if any, revisions could be made. Nonetheless, the Agency expects EGU source owners or operators to comply with the revised startup definition by the date specified in this rule. Given the concern expressed by the commenters for some sources, the Agency expects such source owners or operators to begin negotiations with other parties for other non-rule obligations to begin early enough to be completed prior to the compliance date specified in this rule.

The Agency disagrees with the commenters' suggestions that startup definition paragraph (2)'s reporting requirements were too strict to be used. That suggestion is not consistent with the number of commenters who claimed to need to use paragraph (2) of the startup definition, even though only 2.5 percent of EGUs currently rely on this startup definition. The Agency's experience is that almost all EGU source owners or operators have been able to adjust their unit operation such that adherence to startup definition paragraph (1) reduced, if not eliminated, the concern by some about use of startup definition paragraph (1). As mentioned earlier in this document, the better performers in the coal-fired EGU source category no longer need to have, or use, paragraph (2) of the startup definition after gaining experience with using paragraph (1).

The Agency disagrees with the commenter's suggestion that the diluent cap values allowed for use by 40 CFR part 75 be included in the rule, because diluent cap values are already allowed for use during startup and shutdown periods per 40 CFR 63.10007(f)(1). Note that while emission values are to be recorded and reported during startup and shutdown periods, they are not to be used in compliance calculations per 40 CFR 63.10020(e). In addition to diluent cap use during startup and shutdown periods, section 6.2.2.3 of appendix C to 40 CFR part 63, subpart UUUUU allows diluent cap use for PM CEMS during any periods when oxygen or CO_2 values exceed or dip below, respectively, the cap levels. Diluent cap use for other periods from other regulations are not necessary for MATS. The Agency does not understand the commenter's suggestion concerning the load requirement for a RATA. The Agency believes the commenter may have mistaken HCl CEMS requirements, which use RATAs but were not proposed to be changed, with PM CEMS requirements, which do not use RATAs. Since PM CEMS are not subject to RATAs and the Agency did not propose changes to requirements for HCl CEMS, the comment on RATAs being conducted at greater than 50 percent load is moot. The EPA is finalizing the removal of startup definition paragraph (2), as proposed.

D. What is the rationale for our final approach and final decisions for the startup provisions?

The EPA is finalizing the removal of paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 consistent with reasons described in the 2023 Proposal. As the majority of EGUs are already relying on the work practice standards in paragraph (1) of the startup definition, the EPA finds that such a change is achievable within the 180-day compliance timeline by all EGUs at little to no additional expenditure since the additional reporting and recordkeeping provisions under paragraph (2) were more expensive than paragraph (1). Additionally, the time period for engaging pollution controls for PM or non-Hg HAP metals is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

VIII. What other key comments did we receive on the proposal?

Comment: Some commenters argued that it is well-established that cost is a major consideration in rulemakings reviewing existing NESHAP under CAA section 112(d)(6). In particular, commenters cited to *Michigan* v. *EPA,* 576 U.S. 743, 759 (2015), to support the argument that the EPA must consider the costs of the regulation in relation to the benefits intended by the statutory requirement mandating this regulation, that is, the benefits of the HAP reductions. Commenters stated that the EPA should not seek to impose the excessive costs associated with this action as there would be no benefit associated with reducing HAP. The commenters said that the EPA certainly should not do so for an industry that is rapidly reducing its emissions because it is on the way to retiring most, if not all, units in the source category in little over a decade. The commenters also claimed that as *Michigan* held that cost and benefits must be considered in determining whether it is ''appropriate'' to regulate EGUs under CAA section 112 in the first place, it necessarily follows that the same threshold must also apply when the EPA subsequently reviews the standards.

Response: The EPA agrees that it is appropriate to take costs into consideration in deciding whether it is necessary to revise an existing NESHAP under CAA section 112(d)(6). As explained in the 2023 Proposal and this document, the EPA has carefully considered the costs of compliance and the effects of those costs on the industry. Although the commenters seem to suggest that the EPA should weigh the costs and benefits of the revisions to the standard, we do not interpret the comments as arguing that the EPA should undertake a formal benefit cost analysis but rather the commenters believe that the EPA should instead limit its analysis supporting the standard to HAP emission reductions. Our consideration of costs in this rulemaking is consistent with the Supreme Court's direction in *Michigan* where the Court noted that ''[i]t will be up to the Agency to decide (as always, within the limits of reasonable interpretation) how to account for cost,'' 576 U.S. 743, 759 (2015), and with comments arguing that the EPA should focus its decision-making on the standard on the anticipated reductions in HAP.

In *Michigan,* the Supreme Court concluded that the EPA erred when it concluded it could not consider costs when deciding as a threshold matter whether it is ''appropriate and necessary'' under CAA section 112(n)(1)(A) to regulate HAP from EGUs, despite the relevant statutory provision containing no specific reference to cost. 576 U.S. at 751. In doing so, the Court held that the EPA ''must consider cost—including, most importantly, cost of compliance—before deciding whether regulation is appropriate and necessary'' under CAA section 112. *Id.* at 759. In examining the language of CAA section 112(n)(1)(A), the Court concluded that the phrase ''appropriate and necessary'' was ''capacious'' and held that ''[r]ead naturally in the present context, the phrase 'appropriate and necessary' requires at least some attention to cost.'' *Id.* at 752. As is clear from the record for this rulemaking, the EPA has carefully considered cost in reaching its decision to revise the NESHAP in this action.

The EPA has also taken into account the numerous HAP-related benefits of the final rule in deciding to take this action. These benefits include not only the reduced exposure to Hg and non-Hg HAP metals, but also the additional transparency provided by PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS will provide that the standards are being met on a continuous basis. As discussed in section II.B.2., and section IX.E. many of these important benefits are not able to be monetized. Although this rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium, data limitations prevent the EPA from assigning monetary value to those reductions. In addition, there are several benefits associated with the use of PM CEMS which are not quantified in this rule.

While the Court's examination of CAA section 112(n)(a)(1) in *Michigan* considered a different statutory provision than CAA section 112(d)(6) under which the EPA is promulgating this rulemaking, the EPA has nonetheless satisfied the Court's directive to consider costs, both in the context of the individual revisions to MATS (as directed by the language of the statute) and in the context of the rulemaking as a whole. Moreover, while the EPA is not required to undertake a ''formal cost benefit analysis in which each advantage and disadvantage [of a regulation] is assigned a monetary value,'' *Michigan,* 576 U.S. at 759, the EPA has contemplated and carefully considered both the advantages and disadvantages of the revisions it is finalizing here, including qualitative and quantitative benefits of the regulation and the costs of compliance.

IX. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

The following analyses of costs and benefits, and environmental, economic, and environmental justice impacts are presented for the purpose of providing the public with an understanding of the potential consequences of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discussed in section II.A. and sections IV. through VII.

The EPA's obligation to conduct an analysis of the potential costs and benefits under Executive Order 12866, discussed in this section and section X.A., is distinct from its obligation in setting standards under CAA section 112 to take costs into account. As explained above, the EPA considered costs in multiple ways in choosing appropriate standards consistent with the requirements of CAA section 112. The benefit-cost analysis is performed to comply with Executive Order 12866. The EPA, however, did not rely on that analysis in choosing the appropriate standard here, consistent with the Agency's longstanding interpretation of the statute. As discussed at length in section II.B.2. above and in the EPA's 2023 final rulemaking finalizing the appropriate and necessary finding (88 FR 13956), historically there have been significant challenges in monetizing the benefits of HAP reduction. Important categories of benefits from reducing HAP cannot be monetized, making benefit-cost analysis ill-suited to the EPA's decision making on regulating HAP emissions under CAA section 112. Further, there are also unquantified emission reductions anticipated from installing PM CEMS, as discussed in section IX.E. For this reason, combined with Congress's recognition of the particular dangers posed by HAP and consequent direction to the EPA to reduce emissions of these pollutants to the ''maximum degree,'' the EPA does not at this time believe it is appropriate to rely on the results of the monetized benefit-cost analysis when setting the standards.

As noted in section X.A. below, the EPA projects that the net monetized benefits of this rule are negative. Many of the benefits of this rule discussed at length in this section and elsewhere in this record, however, were not monetized. This rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium,[86] consistent with Congress's direction in CAA section 112 discussed in section II.A. of this final rule. At this time, data limitations prevent the EPA from assigning monetary value to those reductions, as discussed in section II.B.2. above.[87] In addition, the benefits of the additional transparency provided by the requirement to use PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS provide that the standards are being met on a continuous basis were not monetized due to data limitations. While the EPA does not believe benefit-cost analysis is the right way to determine the appropriateness of a standard under CAA section 112, the EPA notes that when all of the costs and benefits are considered (including non-monetized benefits), this final rule is a worthwhile exercise of the EPA's CAA section 112(d)(6) authority.

A. What are the affected facilities?

The EPA estimates that there are 314 coal-fired EGUs [88] and 58 oil-fired EGUs that will be subject to this final rule by the compliance date.

B. What are the air quality impacts?

The EPA estimated emission reductions under the final rule for the years 2028, 2030, and 2035 based upon IPM projections. The quantified emissions estimates were developed with the EPA's Power Sector Modeling Platform 2023 using IPM, a state-of-the-art, peer-reviewed dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. IPM provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies while meeting electricity demand and various environmental, transmission, dispatch, and reliability constraints. IPM's least-cost dispatch

[86] As of 2023, three of the HAP metals or their compounds emitted by EGUs (arsenic, chromium, and nickel) are classified as carcinogenic to humans. More details are available in section II.B.2. and Chapter 4.2.2 of the RIA.

[87] *See also National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023) (for additional discussion regarding the limitations to monetizing and quantifying most benefits from HAP reductions in the 2023 rulemaking finalizing the appropriate and necessary finding).

[88] The number of coal-fired affected EGUs is larger than the 296 coal-fired EGUs assessed for the fPM standard in section IV. because it includes four EGUs that burn petroleum coke (which are a separate subcategory for MATS) and 14 EGUs without fPM compliance data available on the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), *https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

solution is designed to ensure generation resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system. The model includes state-of-the-art estimates of the cost and performance of air pollution control technologies with respect to Hg and other HAP controls.

The quantified emission reduction estimates presented in the RIA include reductions in pollutants directly covered by this rule, such as Hg, and changes in other pollutants emitted from the power sector as a result of the compliance actions projected under this final rule. Table 8 of this document presents the projected emissions under the final rule. Note that, unlike the cost-effectiveness analysis presented in sections IV. and V. of this preamble, the projections presented in table 8 are incremental to a projected baseline which reflects future changes in the composition of the operational coal-fired EGU fleet that are projected to occur by 2035 as a result of factors affecting the power sector, such as the IRA, promulgated regulatory actions, or changes in economic conditions.

BILLING CODE 6560–50–P

Table 8. Projected EGU Emissions in the Baseline and Under the Final Rule: 2028, 2030, and 2035[a]

		Total Emissions			
	Year	Baseline	Final Rule	Change from Baseline	% Change
Hg (lb)	2028	6,129	5,129	-999	-16%
	2030	5,863	4,850	-1,013	-17%
	2035	4,962	4,055	-907	-18%
$PM_{2.5}$ (thousand tons)	2028	70.5	69.7	-0.8	-1.1%
	2030	66.3	65.8	-0.5	-0.8%
	2035	50.7	50.2	-0.5	-0.9%
PM_{10} (thousand tons)	2028	79.5	77.4	-2.1	-2.6%
	2030	74.5	73.1	-1.3	-1.8%
	2035	56.0	54.8	-1.2	-2.1%
SO_2 (thousand tons)	2028	454.3	454.0	-0.3	-0.1%
	2030	333.5	333.5	0.0	0.0%
	2035	239.9	239.9	0.0	0.0%
Ozone-season NO_x (thousand tons)	2028	189.0	188.8	-0.165	-0.09%
	2030	174.9	175.4	0.488	0.28%
	2035	116.9	119.1	2.282	1.95%
Annual NO_x (thousand tons)	2028	460.5	460.3	-0.283	-0.06%
	2030	392.8	392.7	-0.022	-0.01%
	2035	253.4	253.5	0.066	0.03%
HCl (thousand tons)	2028	2.5	2.5	0.0	0.0%
	2030	2.2	2.2	0.0	0.0%
	2035	1.5	1.5	0.0	0.1%
CO_2 (million metric tons)	2028	1,158.8	1,158.7	-0.1	0.0%
	2030	1,098.3	1,098.3	0.0	0.0%
	2035	724.2	724.1	-0.1	0.0%

[a] This analysis is limited to the geographically contiguous lower 48 states.

BILLING CODE 6560–50–C

In addition to the projected emissions impacts presented in table 8, we also estimate that the final rule will reduce at least 7 tons of non-Hg HAP metals in 2028, 5 tons of non-Hg HAP metals in 2030, and 4 tons of non-Hg HAP metals in 2035. These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.[89]

Importantly, the continuous monitoring of fPM required in this rule will likely induce additional emissions reductions that we are unable to quantify. Continuous measurements of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that fPM emissions could be lower than they otherwise would have been for up to 3 months—or up to 3 years if testing less frequently under the LEE program—at a time. This potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the existing coal-fired fleet and is not quantified in this rulemaking.

Section 3 of the RIA presents a detailed discussion of the emissions projections under the regulatory options as described in the RIA. Section 3 also describes the compliance actions that are projected to produce the emission reductions in table 8 of this preamble. Please see section IX.E. of this preamble and section 4 of the RIA for detailed discussions of the projected health, welfare, and climate benefits of these emission reductions.

C. What are the cost impacts?

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In other words, these costs are an estimate of the increased power industry expenditures required to implement the final requirements of this rule. The compliance cost estimates were mainly developed using the EPA's Power Sector Modeling Platform 2023 using IPM. The incremental costs of the final rule's PM CEMS requirement were estimated outside of IPM and added to the IPM-based cost estimate presented here and in section 3 of the RIA.

We estimate the present value (PV) of the projected compliance costs over the 2028 to 2037 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. All dollars are in 2019 dollars. We estimate the PV and EAV using 2, 3, and 7 percent discount rates.[90] Table 9 of this document presents the estimates of compliance costs for the final rule.

Table 9. Projected Compliance Costs of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	2% Discount Rate	3% Discount Rate	7% Discount Rate
PV	860	790	560
EAV	96	92	80

[a] Values have been rounded to two significant figures.

The PV of the compliance costs for the final rule, discounted at the 2 percent rate, is estimated to be about $860 million, with an EAV of about $96 million. At the 3 percent discount rate, the PV of the compliance costs of the final rule is estimated to be about $790 million, with an EAV of about $92 million. At the 7 percent discount rate, the PV of the compliance costs of the rule is estimated to be about $560 million, with an EAV of about $80 million.

We note that IPM provides the EPA's best estimate of the costs of the rules to the electricity sector and related energy sectors (*i.e.,* natural gas, coal mining). These compliance cost estimates are used as a proxy for the social cost of the rule. For a detailed description of these compliance cost projections, please see section 3 of the RIA, which is available in the docket for this action.

D. What are the economic impacts?

The Agency estimates that this rule will require additional fPM and/or Hg removal at less than 15 GW of operable capacity in 2028, which is about 14 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM and/or Hg removal are projected to generate less than 2 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule.

Consistent with the small share of EGUs required to reduce fPM and/or Hg emissions rates, this final action has limited energy market implications. There are limited impacts on energy prices projected to result from this final rule. On a national average basis,

[89] Note that modeled projections include total PM_{10} and total $PM_{2.5}$. The EPA estimated non-Hg HAP metals reductions by multiplying the ratio of non-Hg HAP metals to fPM by modeled projections of total PM_{10} reductions under the rule. The ratios of non-Hg HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-Hg HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-Hg HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category.*

[90] Results using the 2 percent discount rate were not included in the proposal for this action. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

delivered coal, natural gas, and retail electricity prices are not projected to change. The EPA does not project incremental changes in existing operational capacity to occur in response to the final rule. Coal production for use in the power sector is not projected to change significantly by 2028.

The short-term estimates for employment needed to design, construct, and install the control equipment in the 3-year period before the compliance date are also provided using an approach that estimates employment impacts for the environmental protection sector based on projected changes from IPM on the number and scale of pollution controls and labor intensities in relevant sectors. Finally, some of the other types of employment impacts that will be ongoing are estimated using IPM outputs and labor intensities, as reported in section 5 of the RIA.

E. What are the benefits?

The RIA for this action analyzes the benefits associated with the projected emission reductions under this rule. This final rule is projected to reduce emissions of Hg and non-Hg HAP metals, as well as $PM_{2.5}$, SO_2, NO_X and CO_2 nationwide. The potential impacts of these emission reductions are discussed in detail in section 4 of the RIA. The EPA notes that the benefits analysis is distinct from the statutory determinations finalized herein, which are based on the statutory factors the EPA is required to consider under CAA section 112. The assessment of benefits described here and in the RIA is presented solely for the purposes of complying with Executive Order 12866, as amended by Executive Order 14094, and providing the public with a complete depiction of the impacts of the rulemaking.

Hg is a persistent, bioaccumulative toxic metal emitted from power plants that exists in three forms: gaseous elemental Hg, inorganic Hg compounds, and organic Hg compounds (*e.g.,* methylmercury). Hg can also be emitted in a particle-bound form. Elemental Hg can exist as a shiny silver liquid, but readily vaporizes into air. Airborne elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and particle-bound Hg deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, methylmercury is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have methylmercury concentrations many times that of the concentrations in the freshwater body in which they live.

All forms of Hg are toxic, and each form exhibits different health effects. Acute (short-term) exposure to high levels of elemental Hg vapors results in central nervous system (CNS) effects such as tremors, mood changes, and slowed sensory and motor nerve function. Chronic (long-term) exposure to elemental Hg in humans also affects the CNS, with effects such as erethism (increased excitability), irritability, excessive shyness, and tremors. The major effect from chronic ingestion or inhalation of low levels of inorganic Hg is kidney damage.

Methylmercury is the most common organic Hg compound in the environment. Acute exposure of humans to very high levels of methylmercury results in profound CNS effects such as blindness and spastic quadriparesis. Chronic exposure to methylmercury, most commonly by consumption of fish from Hg contaminated waters, also affects the CNS with symptoms such as paresthesia (a sensation of pricking on the skin), blurred vision, malaise, speech difficulties, and constriction of the visual field. Ingestion of methylmercury can lead to significant developmental effects, such as IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability. In addition, evidence in humans and animals suggests that methylmercury can have adverse effects on both the developing and the adult cardiovascular system, including fatal and non-fatal ischemic heart disease (IHD). Further, nephrotoxicity, immunotoxicity, reproductive effects (impaired fertility), and developmental effects have been observed with methylmercury exposure in animal studies.[91] Methylmercury has some genotoxic activity and can cause chromosomal damage in several experimental systems. The EPA has concluded that mercuric chloride and methylmercury are possibly carcinogenic to humans.[92 93]

The projected emissions reductions of Hg are expected to lower deposition of Hg into ecosystems and reduce U.S. EGU attributable bioaccumulation of methylmercury in wildlife, particularly for areas closer to the effected units subject to near-field deposition. Subsistence fishing is associated with vulnerable populations. Methylmercury exposure to subsistence fishers from lignite-fired units is below the current RfD for methylmercury neurodevelopmental toxicity. The EPA considers exposures at or below the RfD for methylmercury unlikely to be associated with appreciable risk of deleterious effects across the population. However, the RfD for methylmercury does not represent an exposure level corresponding to zero risk; moreover, the RfD does not represent a bright line above which individuals are at risk of adverse effects. Reductions in Hg emissions from lignite-fired facilities should further reduce exposure to methylmercury for subsistence fisher sub-populations located in the vicinity of these facilities, which are all located in North Dakota, Texas, and Mississippi.

In addition, U.S. EGUs are a major source of HAP metals emissions including selenium, arsenic, chromium, nickel, and cobalt, cadmium, beryllium, lead, and manganese. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. The emissions reductions projected under this final rule are expected to reduce human exposure to non-Hg HAP metals, including carcinogens.

Furthermore, there is the potential for reductions in Hg and non-Hg HAP metal emissions to enhance ecosystem services and improve ecological outcomes. The reductions will potentially lead to positive economic impacts although it is difficult to estimate these benefits and, consequently, they have not been included in the set of quantified benefits.

As explained in section IX.B., the continuous monitoring of fPM required in this rule may induce further reductions of fPM and non-Hg HAP metals than we project in the RIA for

[91] Agency for Toxic Substances and Disease Registry (ATSDR). Toxicological Profile for Mercury. Public Health Service, U.S. Department of Health and Human Services, Atlanta, GA. 2022.

[92] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 2001.

[93] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Mercuric Chloride. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1995.

this action. As a result, there may be additional unquantified beneficial health impacts from these potential reductions. The continuous monitoring of fPM required in this rule is also likely to provide several additional benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today.

The rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. The rule is also expected to reduce ozone-season NO_X emissions nationally in most years of analysis. In the presence of sunlight, NO_X, and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and reduces the incidence of ozone-related health effects, although the degree to which ozone is reduced will depend in part on local concentration levels of VOCs.

The health effect endpoints, effect estimates, benefit unit values, and how they were selected, are described in the technical support document titled *Estimating $PM_{2.5}$* minus; *and Ozone-Attributable Health Benefits* (2023). This document describes our peer-reviewed approach for selecting and quantifying adverse effects attributable to air pollution, the demographic and health data used to perform these calculations, and our methodology for valuing these effects.

Because of projected changes in dispatch under the final requirements, the rule is also projected to impact CO_2 emissions. The EPA estimates the climate benefits of CO_2 emission reductions expected from the final rule using estimates of the social cost of carbon (SC–CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[94] The EPA published and used these estimates in the RIA for the December 2023 Natural Gas Sector final rule titled *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (2023 Oil and Natural Gas NSPS/EG).[95] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Natural Gas Sector supplemental proposal[96] that preceded the 2023 Oil and Natural Gas NSPS/EG and has conducted an external peer review of these estimates. The response to public comments document and the response to peer reviewer recommendations can be found in the docket for the 2023 Oil and Natural Gas NSPS/EG action. Complete information about the peer review process is also available on the EPA's website.[97]

Section 4.4 within the RIA for this final rulemaking provides an overview of the methodological updates incorporated into the SC–CO_2 estimates used in this final RIA.[98] A more detailed explanation of each input and the modeling process is provided in the final technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.*[99]

The SC–CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CO_2 includes the value of all climate change impacts both negative and positive, including, but not limited to, changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CO_2, therefore, reflects the societal value of reducing emissions of CO_2 by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations restrain the ability of SC–CO_2 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Table 10 of this document presents the estimated PV and EAV of the projected health and climate benefits across the regulatory options examined in the RIA in 2019 dollars discounted to 2023.

BILLING CODE 6560–50–P

[94] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[95] *Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* Docket ID No. EPA–HQ–OAR–2021–0317, December 2023.

[96] *Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* 87 FR 74702 (December 6, 2022).

[97] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.*

[98] Note that the RIA for the proposal of this rulemaking used the SC–CO_2 estimates from the Interagency Working Group's (IWG) February 2021 Social Cost of Greenhouse Gases Technical Support Document (TSD) (IWG 2021) to estimate climate benefits. These SC–CO_2 estimates were interim values recommended for use in benefit-cost analyses until updated estimates of the impacts of climate change could be developed. Estimated climate benefits using these interim SC–CO_2 values (IWG 2021) are presented in Appendix B of the RIA for this final rulemaking for comparison purposes.

[99] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,* Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

Table 10. Projected Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

Present Value (PV)			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Total Monetized Benefits[e]	420	390	300
Equivalent Annual Value (EAV)[b]			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Total Monetized Benefits[e]	47	45	39
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.
[b] The EAV of benefits are calculated over the 10-year period from 2028 to 2037.
[c] The projected monetized air quality-related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent.
[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.
[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

BILLING CODE 6560–50–C

This final rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The projected PV of monetized climate benefits of the final rule is estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent.[100] Thus, this final rule would

[100] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under

generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate.

At a 3 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million discounted at 3 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate.

At a 7 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $180 million, with an EAV of about $25 million discounted at 7 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 7 percent rate.

The benefits from reducing Hg and non-Hg HAP metals and from unquantified improvements in water quality were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this rulemaking. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring PM CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find that, if we were able to monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this document.

F. What analysis of environmental justice did we conduct?

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [101]

The environmental justice analysis is presented for the purpose of providing the public with as full as possible an understanding of the potential impacts of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based solely on the statutory factors the EPA is required to consider under that section. To address these questions in the EPA's first quantitative EJ analysis in the context of a MATS rule, the EPA developed a unique analytical approach that considers the purpose and specifics of this rulemaking, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.,* residence of historically red-lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

For this rule, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns in the baseline (question 1).[102] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standards (NAAQS), whereas the $PM_{2.5}$ metric is more similar to the long-term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to this rulemaking and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

In section 6 of the RIA, we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to various local populations with potential EJ concerns (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment,

OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See Section 4.4 of the RIA for more discussion.

[101] See *https://www.epa.gov/environmental justice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[102] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

and degree of linguistic isolation (section 6.5). It is important to note that due to the small magnitude of underlying emissions changes, and the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes, the rule is expected to have only a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other, as each was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in this final rule, traffic, or noise. The baseline analysis indicates that on average the populations living within 10 kilometers of coal plants potentially impacted by the amended fPM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the American Indian population living within 10 kilometers of lignite plants potentially impacted by the amended Hg standard is higher than the national average. Assessing these results, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* SO_2) for various population groups in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure or impact.

As HAP exposure results generated as part of the 2020 Residual Risk Review were below both the presumptive acceptable cancer risk threshold and noncancer health benchmarks and this regulation should further reduce exposure to HAP, there are no ''disproportionate and adverse effects'' of potential EJ concern. Therefore, we did not perform a quantitative EJ assessment of HAP risk. However, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

This rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and because NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of this rulemaking. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanic, Black, below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications. Due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternative under consideration (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy ozone and $PM_{2.5}$ exposure impacts, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[103]

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action,'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is briefly summarized in section IX. of this preamble and here. This analysis is also available in the docket.

Table 11 of this document presents the estimated PV and EAV of the monetizable projected health benefits, climate benefits, compliance costs, and net benefits of the final rule in 2019 dollars discounted to 2023. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rule.

Under Executive Order 12866, the EPA is directed to consider all of the costs and benefits of its actions, not just those that stem from the regulated pollutant. Accordingly, the projected monetized benefits of the final rule include health benefits associated with projected reductions in $PM_{2.5}$ and ozone concentration. The projected monetized benefits also include climate benefits due to reductions in CO_2 emissions. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent. The projected climate

[103] Please note that results for ozone and $PM_{2.5}$ exposures should not be extrapolated to other air pollutants that were not included in the assessment, including HAP. Detailed EJ analytical results can be found in section 6 of the RIA.

benefits in this table are based on estimates of the SC–CO_2 at a 2 percent near-term Ramsey discount rate and are discounted using a 2 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the finalized requirements and represent the EPA's best estimate of the social cost of the final rulemaking.

BILLING CODE 6560–50–P

Table 11. Projected Monetized Benefits, Compliance Costs, and Net Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	Present Value (PV)		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Compliance Costs	860	790	560
Net Benefits	-440	-400	-260
	Equal Annualized Value (EAV)[b]		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Compliance Costs	96	92	80
Net Benefits	-49	-47	-41
Non-Monetized Benefits[e]	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The EAV of costs and benefits are calculated over the 10-year period from 2028 to 2037.

[c] The projected monetized air quality related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

BILLING CODE 6560–50–C

As shown in table 11 of this document, this rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The rule is also projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent. Thus, this final rule would generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate. The PV of the projected compliance costs are $860 million, with an EAV of about $96 million discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$440 million and EAV of −$49 million.

At a 3 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate. The PV of the projected compliance costs are $790 million, with an EAV of $92 million discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$400 million and an EAV of −$47 million.

At a 7 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $160 million, with an EAV of about $23 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 3 percent rate. The PV of the projected compliance costs are $560 million, with an EAV of $80 million discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$260 million and an EAV of −$41 million.

The potential benefits from reducing Hg and non-Hg HAP metals and potential improvements in water quality and availability were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this final rule. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find, if we were able to quantify and monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2137–12. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0567.

The information collection activities in this rule include continuous emission monitoring, performance testing, notifications and periodic reports, recording information, monitoring and the maintenance of records. The information generated by these activities will be used by the EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable delegated authorities to identify affected facilities that may not be in compliance with the requirements. Based on reported information, delegated authorities will decide which units and what records or processes should be inspected. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). The burden and cost estimates below represent the total burden and cost for the information collection requirements of the NESHAP for Coal- and Oil-Fired EGUs, not just the burden associated with the amendments in this final rule. The incremental cost associated with these amendments is $2.4 million per year.

Respondents/affected entities: The respondents are owners or operators of coal- and oil-fired EGUs. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU industry are 221112, 221122, and 921150.

Respondent's obligation to respond: Mandatory per 42 U.S.C. 7414 *et seq.*

Estimated number of respondents: 192 per year.[104]

Frequency of response: The frequency of responses varies depending on the burden item. Responses include daily calibrations, monthly recordkeeping activities, semiannual compliance reports, and annual reports.

Total estimated burden: 447,000 hours (per year). Burden is defined at 5 CFR part 1320.3(b).

Total estimated cost: $106,600,000 (per year), includes $53,100,000 in annual labor costs and $53,400,000 annualized capital and operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In the 2028 analysis year, the EPA identified 24 potentially affected small entities operating 45 units at 26 facilities, and of these 24, only one small entity may experience compliance cost increases greater than one percent of revenue under the final rule. Details of this analysis are presented in section 5 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more (adjusted for inflation) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The costs involved in this action are estimated not to exceed $100 million or more (adjusted for inflation) in any one year.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive

[104] Each facility is a respondent and some facilities have multiple EGUs.

Order 13175. The Executive order defines tribal implications as ''actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes.'' The amendments in this action would not have a substantial direct effect on one or more tribes, change the relationship between the Federal Government and tribes, or affect the distribution of power and responsibilities between the Federal Government and Indian tribes. Thus, Executive Order 13175 does not apply to this action.

Although this action does not have tribal implications as specified in Executive Order 13175, the EPA consulted with tribal officials during the development of this action. On September 1, 2022, the EPA sent a letter to all federally recognized Indian tribes initiating consultation to obtain input on this action. The EPA did not receive any requests for consultation from Indian tribes. The EPA also participated in the September 2022 National Tribal Air Association EPA Air Policy Update Call to solicit input on this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866. Accordingly, we have evaluated the potential for environmental health or safety effects from exposure to HAP, ozone, and $PM_{2.5}$ on children. The EPA believes that, even though the 2020 residual risk assessment showed all modeled exposures to HAP to be below thresholds for public health concern, the rule should reduce HAP exposure by reducing emissions of Hg and non-Hg HAP with the potential to reduce HAP exposure to vulnerable populations, including children. The action described in this rule is also expected to lower ozone and $PM_{2.5}$ in many areas, including those areas that struggle to attain or maintain the NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated, including children. The results of this evaluation are contained in the RIA and are available in the docket for this action.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For 2028, the compliance year for the standards, the EPA does not project a significant change in retail electricity prices on average across the contiguous U.S., coal-fired electricity generation, natural gas-fired electricity generation, or utility power sector delivered natural gas prices. Details of the projected energy effects are presented in section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

The following standards appear in the amendatory text of this document and were previously approved for the locations in which they appear: ANSI/ASME PTC 19.10–1981, ASTM D6348–03(R2010), and ASTM D6784–16.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. For this rule, we employ the proximity demographic analysis and the $PM_{2.5}$ and ozone exposure analyses to evaluate disproportionate and adverse human health and environmental effects on communities with EJ concerns that exist prior to the action. The proximity demographic analysis indicates that on average the population living within 10 kilometers of coal plants potentially impacted by the fPM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the American Indian population living within 10 kilometers of lignite-fired plants potentially impacted by the Hg standard is higher than the national average. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanics, Blacks, those below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on communities with environmental justice concerns. Only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the final rule, and whether potential EJ concerns will be created or mitigated. We infer that baseline disparities in ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the final regulatory option due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the baseline disparities. We also do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be exacerbated or mitigated in the final regulatory option, compared to the baseline due to the very small differences in the magnitude of post-policy ozone and $PM_{2.5}$ exposure impacts across demographic populations. Additionally, the potential reduction in Hg and non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

The information supporting this Executive Order review is contained in section IX.F. of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket (EPA–HQ–OAR–2018–0794).

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons set forth in the preamble, 40 CFR part 63 is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. In § 63.14, paragraph (f)(1) is amended by removing the text ''tables 4 and 5 to subpart UUUUU'' and adding, in its place, the text ''table 5 to subpart UUUUU''.

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

■ 3. Section 63.9991 is amended by revising paragraph (a)(2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) * * *

(2) Before July 6, 2027, you must meet each operating limit in Table 4 to this subpart that applies to your EGU.

* * * * *

■ 4. Amend § 63.10000 by:

■ a. Revising paragraph (c)(1)(i) and paragraph (c)(1)(i)(A);

■ b. Redesignating paragraph (c)(1)(i)(C) as paragraph (c)(1)(i)(D);

■ c. Adding new paragraph (c)(1)(i)(C);

■ d. Revising paragraph (c)(1)(iv);

■ e. Adding new paragraphs (c)(1)(iv)(A) through (C);

■ f. Revising paragraphs (c)(2)(i) and (ii);

■ g. Revising paragraph (d)(5)(i); and

■ h. Revising paragraph (m) introductory text.

The revisions and additions read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c) * * *

(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) through (C) of this section:

(A) Except as provided in paragraph (c)(1)(i)(D) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

* * * * *

(C) On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for coal-fired and solid oil-derived fuel-fired EGUs.

* * * * *

(iv)(A) Before July 6, 2027, if your coal-fired or solid oil derived fuel-fired EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(B) On and after July 6, 2027, you may not pursue or continue to use the LEE option for your coal-fired or solid oil derived fuel-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(C) If your IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(2) * * *

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals.

(ii) Before July 6, 2027, if your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly. On and after July 6, 2027, you may not pursue or continue to use the LEE option for your liquid oil-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(d) * * *

(5) * * *

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device). See § 63.10010(a) for further details. For PM CPMS installations (which with the exception of IGCC units, are only applicable before July 6, 2027), follow the procedures in § 63.10010(h).

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ''startup'' definition in § 63.10042.

* * * * *

■ 5. Amend § 63.10005 by revising paragraphs (a)(1), (b) introductory text, (c), (d)(2) introductory text, (h) introductory text, and (h)(1) introductory text to read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) * * *

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. Before July 6, 2027, if you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. On and after July 6, 2027, the requirements in Table 4 are not applicable, with the exception of IGCC units. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

* * * * *

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to 40 CFR 63.10007 and Table 5 to this subpart. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5I, 5D, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5I, 5D, 6, 26A, or 29 test (*e.g.,* pitot tube (delta P) readings, moisture collected in the impingers, etc.). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in 40 CFR 63.9984, provided that the following conditions are fully met:

* * * * *

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration. With the exception of IGCC units, on and after July 6, 2027, you may not demonstrate compliance with applicable filterable PM emissions limits with the use of PM CPMS or quarterly stack testing, you may only use PM CEMS.

* * * * *

(d) * * *

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS (with the exception of IGCC units, the use of PM CPMS is only allowed before July 6, 2027):

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) with the exception that on or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for any existing, new or reconstructed EGUs (this does not apply to IGCC units), and if those data demonstrate:

* * * * *

■ 6. Amend § 63.10006 by revising paragraph (a) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS before July 6, 2027 to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year. On or after July 6, 2027 you may not use PM CPMS to demonstrate compliance for liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs. This prohibition against the use of PM CPMS does not apply to IGCC units.

* * * * *

■ 7. Amend § 63.1007 by revising paragraphs (a)(3) and (c) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) * * *

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit (the use of PM CPMS is only allowed before July 6, 2027 with the exception of IGCC units), operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits. On and after July 6, 2027, you must demonstrate continuous compliance with the applicable filterable PM emission standard through the use of a PM CEMS (with the exception that IGCC units are not required to use PM CEMS and may continue to use PM CPMS). Alternatively, you may demonstrate continuous compliance with the non-Hg metals emission standard if you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

* * * * *

■ 8. Amend § 63.10010 by revising paragraphs (a) introductory text, (h) introductory text, (i) introductory text, (j), and (l) introductory text to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS (which on or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit), and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

* * * * *

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit (only applicable before July 6, 2027 unless it is for an IGCC unit), you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

* * * * *

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits (which on or after July 6, 2027 you may not use non-mercury metal HAP limits for compliance demonstrations for existing EGUs unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f)), you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. With the exception of IGCC units, on or after July 6, 2027 owners/operators of existing EGUs must comply with filterable PM emissions limits in Table 2 of this subpart and demonstrate continuous compliance using a PM CEMS unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f). Compliance with the applicable PM emissions limit in Table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

* * * * *

(j) You may choose to comply with the metal HAP emissions limits using CMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CMS and record the output of the HAP metals CMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities, and any scheduled maintenance as defined in your site-specific monitoring plan.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions and repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any out of control periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(C) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits, routine probe maintenance); and

(D) Any data recorded during periods of startup or shutdown.

(ii) You must record and report the results of HAP metals CMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods when the HAP metals CMS is out of control to completion of the corrective actions necessary to return the HAP metals CMS to operation consistent with your site-specific performance evaluation and quality control program plan.

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ''startup'' definition in § 63.10042 for your EGU.

* * * * *

■ 9. Amend § 63.10011 by revising paragraphs (b), (g)(3), and (4) introductory text to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance (with the exception of existing IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 4 p.m. CPMS operating limits do not apply), or if, for an IGCC unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.,* tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 6 procedures for establishing PM CPMS operating limits do not apply unless it is an IGCC unit.

* * * * *

(g) * * *

(3) You must report the emissions data recorded during startup and shutdown. If you are relying on paragraph (2) of the definition of startup in 40 CFR 63.10042 (only allowed before January 2, 2025), then for startup and shutdown incidents that occur on or prior to December 31, 2023, you must also report the applicable supplementary information in 40 CFR 63.10031(c)(5) in the semiannual compliance report. For startup and shutdown incidents that occur on or after January 1, 2024, you must provide the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

(4) If you choose to use paragraph (2) of the definition of ''startup'' in § 63.10042 (only allowed before January 2, 2025), and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of ''startup'' in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

* * * * *

■ 10. Section 63.10020 is amended by revising paragraphs (e) introductory text and (e)(3)(i) introductory text to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025).

* * * * *

(3) * * *

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS (except that unless it is for an IGCC unit, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, and you may not purse or continue to use the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals), you must:

* * * * *

■ 11. Section 63.10021 is amended by revising paragraphs (c) introductory text and (i) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(c) If you use PM CPMS data (only allowed before July 6, 2027 unless it is for an IGCC unit) to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.,* milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations unless it is for an IGCC unit.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq.\ 9)$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

* * * * *

(i) Before January 2, 2025, if you are relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, you must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.

■ 12. Section 63.10022 is amended by revising paragraphs (a)(2) and (3) to read as follows:

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) * * *

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test. On or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies. Since on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit, for compliance demonstrations with the applicable filterable PM limits, the Table 4 p.m. CPMS operating limits do not apply.

* * * * *

■ 13. Section 63.10023 is amended by adding introductory text to the section to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

The provisions of this section § 63.10023 are only applicable before July 6, 2027 unless it is for an IGCC unit. On or after July 6, 2027 you may not use PM CPMS, unless it is an IGCC unit, for demonstrating compliance with the filterable PM emissions limits of this subpart.

* * * * *

■ 14. Section 63.10030 is amended by revising paragraphs (e)(3), (8) introductory text, and (8)(i) introductory text to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.,* use of PM CPMS—which on or after July 6, 2027—you may not use for filterable PM compliance demonstrations, unless it is for an IGCC unit); CEMS; or a sorbent trap monitoring system.

* * * * *

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ''startup'' in § 63.10042. On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

(i) Before January 2, 2025 should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you shall include a report that identifies:

* * * * *

■ 15. Section 63.10031 is amended by revising paragraphs (a)(4), (c)(5) introductory text, (f)(2), (i), and (k) to read as follows:

§ 63.10031 What reports must I submit and when?

(a) * * *

(4) Before July 6, 2027, if you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Except for IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(c) * * *

(5) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), for each instance of startup or shutdown you shall:

* * * * *

(f) * * *

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit), you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

* * * * *

(i) If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 (only allowed before January 2, 2025), then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report.

* * * * *

(k) If you elect to demonstrate compliance using a PM CPMS (on or after July 6, 2027 you may not demonstrate compliance with filterable PM emissions limits using a PM CPMS, unless it is for an IGCC unit) or an approved HAP metals CMS, you must submit quarterly reports of your QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.

■ 16. Section 63.10032 is amended by revising paragraphs (a) introductory text and (f)(2) introductory text to read as follows:

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

* * * * *

(f) * * *

(2) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (on or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042), you must keep records of:

* * * * *

■ 17. Section 63.10042 is amended by revising the definition ''Startup'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Startup means:

(1) The first-ever firing of fuel in a boiler for the purpose of producing

electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

(2) Alternatively, prior to January 2, 2025, the period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

* * * * *

■ 18. Revise table 1 to subpart UUUUU of part 63 to read as follows:

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1]	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Mercury (Hg)	Before July 8, 2024: 4.0E–2 lb/GWh; On or after July 8, 2024: 1.3E–2 lb/GWh.	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh [4] 9.0E–2 lb/MWh [5].	Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B at appendix A–8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross output.
[5] Duct burners on natural gas; gross output.

■ 19. Revise table 2 to subpart UUUUU of part 63 to read as follows:

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits: [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
		On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh [2].	On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO_2) [4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	Before July 6, 2027: 4.0E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2].	Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals ..	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn) ...	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF).	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn) ...	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO_2)[4].	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit.	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2) [4].	6E–1 lb/MMBtu or 9E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
	OR	1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).
[2] Gross output.
[3] Incorporated by reference, *see* § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 20. Revise table 3 to subpart UUUUU of part 63 to read as follows:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in § 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	a. Before January 2, 2025 you have the option of complying using either of the following work practice standards in paragraphs (1) and (2). On or after January 2, 2025 you may not choose to use paragraph (2) of the definition of startup in § 63.10042 and the following associated work practice standards in paragraph (2).

If your EGU is . . .	You must meet the following . . .
	(1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your PM control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10021(h) and 63.10032. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.

If your EGU is . . .	You must meet the following . . .
	You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

■ 21. Revise table 4 to subpart UUUUU of part 63 to read as follows:

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

Before July 6, 2027, as stated in § 63.9991, you must comply with the applicable operating limits in table 4. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 22. Revise table 5 to subpart UUUUU of part 63 to read as follows:

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

BILLING CODE 6560–50–P

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 and 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 or 5I front half temperature shall be 160° ±14 °C (320° ±25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.

		maintain the PM CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must

		each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF	Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at

		emissions concentrations	appendix A to part 63 of this chapter or ASTM D6348-03 Reapproved 2010[3] with
			(1) the following conditions when using ASTM D6348-03 Reapproved 2010:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03 Reapproved 2010, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Reapproved 2010 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 Reapproved 2010 test data to be acceptable for a target analyte, %R must be 70% ≥R ≤130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\ 100$
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		monitoring systems	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784,[3] or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and	Sections 3.2.1 and 5.1 of appendix A of this subpart.

		maintain the CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh	Section 6 of appendix A to this subpart.

		emissions rates	
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

BILLING CODE 6560–50–C

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h). With the exception of IGCC units, on or after July 6, 2027: You may not use quarterly performance emissions testing to demonstrate compliance with the filterable PM emissions standards and for existing EGUs you may not choose to comply with the total or individual HAP metals emissions limits unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

■ 23. Revise table 6 to subpart UUUUU of part 63 to read as follows:

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

Before July 6, 2027, as stated in § 63.10007, you must comply with the following requirements for establishing operating limits in table 6. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 24. Revise table 7 to subpart UUUUU of part 63 to read as follows:

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit. (On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.).	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (*e.g.,* milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2. (On or after July 6, 2027 you may not use quarterly performance testing for filterable PM compliance demonstrations, unless it is for an IGCC unit.).	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

■ 25. Revise table 8 to subpart UUUUU of part 63 to read as follows:

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

[In accordance with 40 CFR 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

You must submit the following reports . . .
1. The electronic reports required under 40 CFR 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under 40 CFR 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under 40 CFR 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under 40 CFR 63.10031(a)(4), if you elect to use a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit).
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under 40 CFR 63.10031(a)(5), if you continuously monitor SO_2 emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to the introductory text of 40 CFR 63.10031(f) and 40 CFR 63.10031(f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in 40 CFR 63.10023(b)(2)(vi).
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under 40 CFR 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO_2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to 40 CFR 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO_2 or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.

You must submit the following reports . . .
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit), according to 40 CFR 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90-group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.
11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.
12. Quarterly reports, in PDF files, that include the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in 40 CFR 63.10042 (see 40 CFR 63.10031(i)). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under 40 CFR 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS Client Tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit) or approved HAP metals CMS (as applicable), in PDF files, according to 40 CFR 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

■ 26. In appendix C to subpart UUUUU:

■ a. Revise sections 1.2, 1.3, 4.1, and 4.1.1.

■ b. Add sections 4.1.1.1 and 4.2.3.

■ c. Revise sections 5.1.1, 5.1.4, and the section heading for section 6.

The revisions and additions read as follows:

Appendix C to Subpart UUUUU of Part 63—PM Monitoring Provisions

1. General Provisions

* * * * *

1.2 *Initial Certification and Recertification Procedures.* You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in Table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to Performance Specification 11 (PS–11) in appendix B to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

1.3 *Quality Assurance and Quality Control Requirements.* You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in Procedure 2, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. However, if you have developed and are using a correlation curve, you may continue to use that curve, provided it continues to meet the acceptance criteria in PS–11 and Procedure 2 as discussed below. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1 PM CEMS. You must certify your PM CEMS according to PS–11 in appendix B to part 60 of this chapter. A PM CEMS that has been installed and certified according to PS–11 as a result of another state or federal regulatory requirement or consent decree prior to the effective date of this subpart shall be considered certified for this subpart if you can demonstrate that your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 in appendix F to part 60 of this chapter.

4.1.1.1 Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4.2 Recertification.

* * * * *

4.2.3 Beginning on July 6, 2027 you must use the value of 0.015 lb/MMBtu in place of the applicable emission standard, or emission limit, in the calculations when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

5.1.1 Required QA Tests. Following initial certification, you must conduct periodic QA testing of each primary and (if applicable) redundant backup PM CEMS. The required QA tests and the criteria that must be met are found in Procedure 2 of appendix F to part 60 of this chapter

(Procedure 2). Except as otherwise provided in section 5.1.2 of this appendix, the QA tests shall be done at the frequency specified in Procedure 2.

* * * * *

5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA. However, beginning on July 6, 2027 a value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, when determining whether the RCA and RRA are acceptable.

* * * * *

6. Data Reduction and Calculations

* * * * *

■ 27. Appendix D to subpart UUUUU of part 63 is amended by adding introductory text to the appendix to read as follows:

Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, unless it is for an IGCC unit.

* * * * *

[FR Doc. 2024–09148 Filed 5–6–24; 8:45 am]

BILLING CODE 6560–50–P

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1119 **September Term, 2023**

EPA-89FR38508

Filed On: August 6, 2024

State of North Dakota, et al.,

Petitioners

v.

Environmental Protection Agency,

Respondent

San Miguel Electric Cooperative, Inc., et al.,
Intervenors

Consolidated with 24-1154, 24-1179,
24-1184, 24-1190, 24-1194, 24-1201,
24-1217, 24-1223

BEFORE: Henderson, Pan, and Garcia, Circuit Judges

O R D E R

Upon consideration of the motions for stay pending review, the oppositions thereto, the replies, and the Rule 28(j) letter, it is

ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending court review. See Nken v. Holder, 556 U.S. 418, 434 (2009); D.C. Circuit Handbook of Practice and Internal Procedures 33 (2021). It is

FURTHER ORDERED, on the court's own motion, that the parties submit, within 14 days from the date of this order, proposed formats and schedules for the briefing of these cases. The parties are strongly urged to submit a joint proposal and are reminded that the court looks with extreme disfavor on repetitious submissions and will, where appropriate, require a joint brief of aligned parties with total words not to exceed the standard allotment for a single brief. Whether the parties are aligned or have disparate interests, they must provide detailed justifications for any request to file

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1119 **September Term, 2023**

separate briefs or to exceed in the aggregate the standard word allotment. Requests to exceed the standard word allotment must specify the word allotment necessary for each issue.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Selena R. Gancasz
Deputy Clerk

APPENDIX B

STATUTORY PROVISION INVOLVED

Pub. L. 95–95, § 109(f), added par. (7) directing that under certain circumstances a conversion to coal not be deemed a modification for purposes of pars. (2) and (4).

Subsec. (a)(7), (8). Pub. L. 95–190, § 14(a)(7), redesignated second par. (7) as (8).

Subsec. (b)(1)(A). Pub. L. 95–95, § 401(b), substituted ''such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger'' for ''such list if he determines it may contribute significantly to air pollution which causes or contributes to the endangerment of''.

Subsec. (b)(1)(B). Pub. L. 95–95, § 109(c)(2), substituted ''shall, at least every four years, review and, if appropriate,'' for ''may, from time to time,''.

Subsec. (b)(5), (6). Pub. L. 95–95, § 109(c)(3), added pars. (5) and (6).

Subsec. (c)(1). Pub. L. 95–95, § 109(d)(1), struck out ''(except with respect to new sources owned or operated by the United States)'' after ''implement and enforce such standards''.

Subsec. (d)(1). Pub. L. 95–95, § 109(b)(1), substituted ''standards of performance'' for ''emission standards'' and inserted provisions directing that regulations of the Administrator permit the State, in applying a standard of performance to any particular source under a submitted plan, to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies.

Subsec. (d)(2). Pub. L. 95–95, § 109(b)(2), provided that, in promulgating a standard of performance under a plan, the Administrator take into consideration, among other factors, the remaining useful lives of the sources in the category of sources to which the standard applies.

Subsecs. (f) to (i). Pub. L. 95–95, § 109(a), added subsecs. (f) to (i).

Subsecs. (j), (k). Pub. L. 95–190, § 14(a)(8), (9), redesignated subsec. (k) as (j) and, as so redesignated, substituted ''(B)'' for ''(8)'' as designation for second subpar. in par. (2). Former subsec. (j), added by Pub. L. 95–95, § 109(e), which related to compliance with applicable standards of performance, was struck out.

Pub. L. 95–95, § 109(e), added subsec. (k).

1971—Subsec. (b)(1)(B). Pub. L. 92–157 substituted in first sentence ''publish proposed'' for ''propose''.

Statutory Notes and Related Subsidiaries

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

REGULATIONS

Pub. L. 101–549, title IV, § 403(b), (c), Nov. 15, 1990, 104 Stat. 2631, provided that:

''(b) REVISED REGULATIONS.—Not later than three years after the date of enactment of the Clean Air Act Amendments of 1990 [Nov. 15, 1990], the Administrator shall promulgate revised regulations for standards of performance for new fossil fuel fired electric utility units commencing construction after the date on which such regulations are proposed that, at a minimum, require any source subject to such revised standards to emit sulfur dioxide at a rate not greater than would have resulted from compliance by such source with the applicable standards of performance under this section [amending sections 7411 and 7479 of this title] prior to such revision.

''(c) APPLICABILITY.—The provisions of subsections (a) [amending this section] and (b) apply only so long as the provisions of section 403(e) of the Clean Air Act [42 U.S.C. 7651b(e)] remain in effect.''

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

Executive Documents

TRANSFER OF FUNCTIONS

Enforcement functions of Administrator or other official in Environmental Protection Agency related to compliance with new source performance standards under this section with respect to pre-construction, construction, and initial operation of transportation system for Canadian and Alaskan natural gas transferred to Federal Inspector, Office of Federal Inspector for the Alaska Natural Gas Transportation System, until first anniversary of date of initial operation of Alaska Natural Gas Transportation System, see Reorg. Plan No. 1 of 1979, eff. July 1, 1979, §§ 102(a), 203(a), 44 F.R. 33663, 33666, 93 Stat. 1373, 1376, set out in the Appendix to Title 5, Government Organization and Employees. Office of Federal Inspector for the Alaska Natural Gas Transportation System abolished and functions and authority vested in Inspector transferred to Secretary of Energy by section 3012(b) of Pub. L. 102–486, set out as an Abolition of Office of Federal Inspector note under section 719e of Title 15, Commerce and Trade. Functions and authority vested in Secretary of Energy subsequently transferred to Federal Coordinator for Alaska Natural Gas Transportation Projects by section 720d(f) of Title 15.

POWER SECTOR CARBON POLLUTION STANDARDS

Memorandum of President of the United States, June 25, 2013, 78 F.R. 39535, which related to carbon pollution standards for power plants, was revoked by Ex. Ord. No. 13783, § 3(a)(ii), Mar. 28, 2017, 82 F.R. 16094, formerly set out as a note under section 13201 of this title.

§ 7412. Hazardous air pollutants

(a) Definitions

For purposes of this section, except subsection (r)—

(1) Major source

The term ''major source'' means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. The Administrator may establish a lesser quantity, or in the case of radionuclides different criteria, for a major source than that specified in the previous sentence, on the basis of the potency of the air pollutant, persistence, potential for bioaccumulation, other characteristics of the air pollutant, or other relevant factors.

(2) Area source

The term ''area source'' means any stationary source of hazardous air pollutants that is not a major source. For purposes of this section, the term ''area source'' shall not include motor vehicles or nonroad vehicles subject to regulation under subchapter II.

(3) Stationary source

The term ''stationary source'' shall have the same meaning as such term has under section 7411(a) of this title.

(4) New source

The term ''new source'' means a stationary source the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emission standard applicable to such source.

(5) Modification

The term ''modification'' means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount.

(6) Hazardous air pollutant

The term ''hazardous air pollutant'' means any air pollutant listed pursuant to subsection (b).

(7) Adverse environmental effect

The term ''adverse environmental effect'' means any significant and widespread adverse effect, which may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas.

(8) Electric utility steam generating unit

The term ''electric utility steam generating unit'' means any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.

(9) Owner or operator

The term ''owner or operator'' means any person who owns, leases, operates, controls, or supervises a stationary source.

(10) Existing source

The term ''existing source'' means any stationary source other than a new source.

(11) Carcinogenic effect

Unless revised, the term ''carcinogenic effect'' shall have the meaning provided by the Administrator under Guidelines for Carcinogenic Risk Assessment as of the date of enactment.[1] Any revisions in the existing Guidelines shall be subject to notice and opportunity for comment.

(b) List of pollutants

(1) Initial list

The Congress establishes for purposes of this section a list of hazardous air pollutants as follows:

CAS number	Chemical name
75070	Acetaldehyde
60355	Acetamide
75058	Acetonitrile
98862	Acetophenone
53963	2-Acetylaminofluorene
107028	Acrolein
79061	Acrylamide
79107	Acrylic acid
107131	Acrylonitrile
107051	Allyl chloride
92671	4-Aminobiphenyl
62533	Aniline
90040	o-Anisidine
1332214	Asbestos
71432	Benzene (including benzene from gasoline)
92875	Benzidine
98077	Benzotrichloride
100447	Benzyl chloride
92524	Biphenyl
117817	Bis(2-ethylhexyl)phthalate (DEHP)
542881	Bis(chloromethyl)ether
75252	Bromoform
106990	1,3-Butadiene
156627	Calcium cyanamide
105602	Caprolactam
133062	Captan
63252	Carbaryl
75150	Carbon disulfide
56235	Carbon tetrachloride
463581	Carbonyl sulfide
120809	Catechol
133904	Chloramben
57749	Chlordane
7782505	Chlorine
79118	Chloroacetic acid
532274	2-Chloroacetophenone
108907	Chlorobenzene
510156	Chlorobenzilate
67663	Chloroform
107302	Chloromethyl methyl ether
126998	Chloroprene
1319773	Cresols/Cresylic acid (isomers and mixture)
95487	o-Cresol
108394	m-Cresol
106445	p-Cresol
98828	Cumene
94757	2,4-D, salts and esters
3547044	DDE
334883	Diazomethane
132649	Dibenzofurans
96128	1,2-Dibromo-3-chloropropane
84742	Dibutylphthalate
106467	1,4-Dichlorobenzene(p)
91941	3,3-Dichlorobenzidene
111444	Dichloroethyl ether (Bis(2-chloroethyl)ether)
542756	1,3-Dichloropropene
62737	Dichlorvos
111422	Diethanolamine

[1] See References in Text note below.

CAS number	Chemical name
121697	N,N-Diethyl aniline (N,N-Dimethylaniline)
64675	Diethyl sulfate
119904	3,3-Dimethoxybenzidine
60117	Dimethyl aminoazobenzene
119937	3,3′-Dimethyl benzidine
79447	Dimethyl carbamoyl chloride
68122	Dimethyl formamide
57147	1,1-Dimethyl hydrazine
131113	Dimethyl phthalate
77781	Dimethyl sulfate
534521	4,6-Dinitro-o-cresol, and salts
51285	2,4-Dinitrophenol
121142	2,4-Dinitrotoluene
123911	1,4-Dioxane (1,4-Diethyleneoxide)
122667	1,2-Diphenylhydrazine
106898	Epichlorohydrin (l-Chloro-2,3-epoxypropane)
106887	1,2-Epoxybutane
140885	Ethyl acrylate
100414	Ethyl benzene
51796	Ethyl carbamate (Urethane)
75003	Ethyl chloride (Chloroethane)
106934	Ethylene dibromide (Dibromoethane)
107062	Ethylene dichloride (1,2-Dichloroethane)
107211	Ethylene glycol
151564	Ethylene imine (Aziridine)
75218	Ethylene oxide
96457	Ethylene thiourea
75343	Ethylidene dichloride (1,1-Dichloroethane)
50000	Formaldehyde
76448	Heptachlor
118741	Hexachlorobenzene
87683	Hexachlorobutadiene
77474	Hexachlorocyclopentadiene
67721	Hexachloroethane
822060	Hexamethylene-1,6-diisocyanate
680319	Hexamethylphosphoramide
110543	Hexane
302012	Hydrazine
7647010	Hydrochloric acid
7664393	Hydrogen fluoride (Hydrofluoric acid)
123319	Hydroquinone
78591	Isophorone
58899	Lindane (all isomers)
108316	Maleic anhydride
67561	Methanol
72435	Methoxychlor
74839	Methyl bromide (Bromomethane)
74873	Methyl chloride (Chloromethane)
71556	Methyl chloroform (1,1,1-Trichloroethane)
78933	Methyl ethyl ketone (2-Butanone)
60344	Methyl hydrazine
74884	Methyl iodide (Iodomethane)
108101	Methyl isobutyl ketone (Hexone)
624839	Methyl isocyanate
80626	Methyl methacrylate
1634044	Methyl tert butyl ether
101144	4,4-Methylene bis(2-chloroaniline)
75092	Methylene chloride (Dichloromethane)
101688	Methylene diphenyl diisocyanate (MDI)
101779	4,4′-Methylenedianiline
91203	Naphthalene
98953	Nitrobenzene
92933	4-Nitrobiphenyl
100027	4-Nitrophenol
79469	2-Nitropropane
684935	N-Nitroso-N-methylurea
62759	N-Nitrosodimethylamine
59892	N-Nitrosomorpholine
56382	Parathion
82688	Pentachloronitrobenzene (Quintobenzene)
87865	Pentachlorophenol
108952	Phenol
106503	p-Phenylenediamine
75445	Phosgene
7803512	Phosphine
7723140	Phosphorus
85449	Phthalic anhydride
1336363	Polychlorinated biphenyls (Aroclors)
1120714	1,3-Propane sultone
57578	beta-Propiolactone
123386	Propionaldehyde
114261	Propoxur (Baygon)
78875	Propylene dichloride (1,2-Dichloropropane)
75569	Propylene oxide
75558	1,2-Propylenimine (2-Methyl aziridine)
91225	Quinoline
106514	Quinone
100425	Styrene
96093	Styrene oxide
1746016	2,3,7,8-Tetrachlorodibenzo-p-dioxin
79345	1,1,2,2-Tetrachloroethane
127184	Tetrachloroethylene (Perchloroethylene)
7550450	Titanium tetrachloride
108883	Toluene
95807	2,4-Toluene diamine
584849	2,4-Toluene diisocyanate
95534	o-Toluidine
8001352	Toxaphene (chlorinated camphene)
120821	1,2,4-Trichlorobenzene
79005	1,1,2-Trichloroethane
79016	Trichloroethylene
95954	2,4,5-Trichlorophenol
88062	2,4,6-Trichlorophenol
121448	Triethylamine
1582098	Trifluralin
540841	2,2,4-Trimethylpentane
108054	Vinyl acetate
593602	Vinyl bromide
75014	Vinyl chloride
75354	Vinylidene chloride (1,1-Dichloroethylene)
1330207	Xylenes (isomers and mixture)
95476	o-Xylenes
108383	m-Xylenes
106423	p-Xylenes
0	Antimony Compounds
0	Arsenic Compounds (inorganic including arsine)
0	Beryllium Compounds
0	Cadmium Compounds
0	Chromium Compounds
0	Cobalt Compounds
0	Coke Oven Emissions
0	Cyanide Compounds[1]
0	Glycol ethers[2]
0	Lead Compounds
0	Manganese Compounds
0	Mercury Compounds
0	Fine mineral fibers[3]
0	Nickel Compounds
0	Polycylic Organic Matter[4]
0	Radionuclides (including radon)[5]
0	Selenium Compounds

NOTE: For all listings above which contain the word ''compounds'' and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

[1] X′CN where X = H′ or any other group where a formal dissociation may occur. For example KCN or $Ca(CN)_2$.

[2] Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol R–(OCH2CH2)$_n$–OR′ where

n = 1, 2, or 3

R = alkyl or aryl groups

R′ = R, H, or groups which, when removed, yield glycol ethers with the structure: R–(OCH2CH)$_n$–OH. Polymers are excluded from the glycol category.

[3] Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

[4] Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C.

[5] A type of atom which spontaneously undergoes radioactive decay.

(2) Revision of the list

The Administrator shall periodically review the list established by this subsection and publish the results thereof and, where appropriate, revise such list by rule, adding pollutants which present, or may present, through inhalation or other routes of exposure, a threat of adverse human health effects (including, but not limited to, substances which are known to be, or may reasonably be anticipated to be, carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic) or adverse environmental effects whether through ambient concentrations, bioaccumulation, deposition, or otherwise, but not including releases subject to regulation under subsection (r) as a result of emissions to the air. No air pollutant which is listed under section 7408(a) of this title may be added to the list under this section, except that the prohibition of this sentence shall not apply to any pollutant which independently meets the listing criteria of this paragraph and is a precursor to a pollutant which is listed under section 7408(a) of this title or to any pollutant which is in a class of pollutants listed under such section. No substance, practice, process or activity regulated under subchapter VI of this chapter shall be subject to regulation under this section solely due to its adverse effects on the environment.

(3) Petitions to modify the list

(A) Beginning at any time after 6 months after November 15, 1990, any person may petition the Administrator to modify the list of hazardous air pollutants under this subsection by adding or deleting a substance or, in case of listed pollutants without CAS numbers (other than coke oven emissions, mineral fibers, or polycyclic organic matter) removing certain unique substances. Within 18 months after receipt of a petition, the Administrator shall either grant or deny the petition by publishing a written explanation of the reasons for the Administrator's decision. Any such petition shall include a showing by the petitioner that there is adequate data on the health or environmental defects[2] of the pollutant or other evidence adequate to support the petition. The Administrator may not deny a petition solely on the basis of inadequate resources or time for review.

(B) The Administrator shall add a substance to the list upon a showing by the petitioner or on the Administrator's own determination that the substance is an air pollutant and that emissions, ambient concentrations, bioaccumulation or deposition of the substance are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects.

(C) The Administrator shall delete a substance from the list upon a showing by the petitioner or on the Administrator's own determination that there is adequate data on the health and environmental effects of the substance to determine that emissions, ambient concentrations, bioaccumulation or deposition of the substance may not reasonably be anticipated to cause any adverse effects to the human health or adverse environmental effects.

(D) The Administrator shall delete one or more unique chemical substances that contain a listed hazardous air pollutant not having a CAS number (other than coke oven emissions, mineral fibers, or polycyclic organic matter) upon a showing by the petitioner or on the Administrator's own determination that such unique chemical substances that contain the named chemical of such listed hazardous air pollutant meet the deletion requirements of subparagraph (C). The Administrator must grant or deny a deletion petition prior to promulgating any emission standards pursuant to subsection (d) applicable to any source category or subcategory of a listed hazardous air pollutant without a CAS number listed under subsection (b) for which a deletion petition has been filed within 12 months of November 15, 1990.

(4) Further information

If the Administrator determines that information on the health or environmental effects of a substance is not sufficient to make a determination required by this subsection, the Administrator may use any authority available to the Administrator to acquire such information.

(5) Test methods

The Administrator may establish, by rule, test measures and other analytic procedures for monitoring and measuring emissions, ambient concentrations, deposition, and bioaccumulation of hazardous air pollutants.

(6) Prevention of significant deterioration

The provisions of part C (prevention of significant deterioration) shall not apply to pollutants listed under this section.

(7) Lead

The Administrator may not list elemental lead as a hazardous air pollutant under this subsection.

(c) List of source categories

(1) In general

Not later than 12 months after November 15, 1990, the Administrator shall publish, and shall from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information, a list of all categories and subcategories of major sources and area sources (listed under paragraph (3)) of the air pollutants listed pursuant to subsection (b). To the extent practicable, the categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to section 7411 of this title and part C. Nothing in the preceding sentence limits the Administrator's authority to establish subcategories under this section, as appropriate.

(2) Requirement for emissions standards

For the categories and subcategories the Administrator lists, the Administrator shall es-

[2] So in original. Probably should be "effects".

tablish emissions standards under subsection (d), according to the schedule in this subsection and subsection (e).

(3) Area sources

The Administrator shall list under this subsection each category or subcategory of area sources which the Administrator finds presents a threat of adverse effects to human health or the environment (by such sources individually or in the aggregate) warranting regulation under this section. The Administrator shall, not later than 5 years after November 15, 1990, and pursuant to subsection (k)(3)(B), list, based on actual or estimated aggregate emissions of a listed pollutant or pollutants, sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas are subject to regulation under this section. Such regulations shall be promulgated not later than 10 years after November 15, 1990.

(4) Previously regulated categories

The Administrator may, in the Administrator's discretion, list any category or subcategory of sources previously regulated under this section as in effect before November 15, 1990.

(5) Additional categories

In addition to those categories and subcategories of sources listed for regulation pursuant to paragraphs (1) and (3), the Administrator may at any time list additional categories and subcategories of sources of hazardous air pollutants according to the same criteria for listing applicable under such paragraphs. In the case of source categories and subcategories listed after publication of the initial list required under paragraph (1) or (3), emission standards under subsection (d) for the category or subcategory shall be promulgated within 10 years after November 15, 1990, or within 2 years after the date on which such category or subcategory is listed, whichever is later.

(6) Specific pollutants

With respect to alkylated lead compounds, polycyclic organic matter, hexachlorobenzene, mercury, polychlorinated biphenyls, 2,3,7,8-tetrachlorodibenzofurans and 2,3,7,8-tetrachlorodibenzo-p-dioxin, the Administrator shall, not later than 5 years after November 15, 1990, list categories and subcategories of sources assuring that sources accounting for not less than 90 per centum of the aggregate emissions of each such pollutant are subject to standards under subsection (d)(2) or (d)(4). Such standards shall be promulgated not later than 10 years after November 15, 1990. This paragraph shall not be construed to require the Administrator to promulgate standards for such pollutants emitted by electric utility steam generating units.

(7) Research facilities

The Administrator shall establish a separate category covering research or laboratory facilities, as necessary to assure the equitable treatment of such facilities. For purposes of this section, "research or laboratory facility" means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a de minimis manner.

(8) Boat manufacturing

When establishing emissions standards for styrene, the Administrator shall list boat manufacturing as a separate subcategory unless the Administrator finds that such listing would be inconsistent with the goals and requirements of this chapter.

(9) Deletions from the list

(A) Where the sole reason for the inclusion of a source category on the list required under this subsection is the emission of a unique chemical substance, the Administrator shall delete the source category from the list if it is appropriate because of action taken under either subparagraphs (C) or (D) of subsection (b)(3).

(B) The Administrator may delete any source category from the list under this subsection, on petition of any person or on the Administrator's own motion, whenever the Administrator makes the following determination or determinations, as applicable:

(i) In the case of hazardous air pollutants emitted by sources in the category that may result in cancer in humans, a determination that no source in the category (or group of sources in the case of area sources) emits such hazardous air pollutants in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources).

(ii) In the case of hazardous air pollutants that may result in adverse health effects in humans other than cancer or adverse environmental effects, a determination that emissions from no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source (or from a group of sources in the case of area sources).

The Administrator shall grant or deny a petition under this paragraph within 1 year after the petition is filed.

(d) Emission standards

(1) In general

The Administrator shall promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation pursuant to subsection (c) in accordance with the schedules provided in subsections (c) and (e). The Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards except that, there shall be no delay in the compliance date for any standard applicable to any source under subsection (i) as the result of the authority provided by this sentence.

(2) Standards and methods

Emissions standards promulgated under this subsection and applicable to new or existing sources of hazardous air pollutants shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies, through application of measures, processes, methods, systems or techniques including, but not limited to, measures which—

(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,

(B) enclose systems or processes to eliminate emissions,

(C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,

(D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h), or

(E) are a combination of the above.

None of the measures described in subparagraphs (A) through (D) shall, consistent with the provisions of section 7414(c) of this title, in any way compromise any United States patent or United States trademark right, or any confidential business information, or any trade secret or any other intellectual property right.

(3) New and existing sources

The maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated under this subsection for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than—

(A) the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 7501 of this title) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources, or

(B) the average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources.

(4) Health threshold

With respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection.

(5) Alternative standard for area sources

With respect only to categories and subcategories of area sources listed pursuant to subsection (c), the Administrator may, in lieu of the authorities provided in paragraph (2) and subsection (f), elect to promulgate standards or requirements applicable to sources in such categories or subcategories which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants.

(6) Review and revision

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

(7) Other requirements preserved

No emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section 7411 of this title, part C or D, or other authority of this chapter or a standard issued under State authority.

(8) Coke ovens

(A) Not later than December 31, 1992, the Administrator shall promulgate regulations establishing emission standards under paragraphs (2) and (3) of this subsection for coke oven batteries. In establishing such standards, the Administrator shall evaluate—

(i) the use of sodium silicate (or equivalent) luting compounds to prevent door leaks, and other operating practices and technologies for their effectiveness in reducing coke oven emissions, and their suitability for use on new and existing coke oven batteries, taking into account costs and reasonable commercial door warranties; and

(ii) as a basis for emission standards under this subsection for new coke oven batteries that begin construction after the date of proposal of such standards, the Jewell design Thompson non-recovery coke oven batteries and other non-recovery coke oven technologies, and other appropriate emission control and coke production technologies, as to their effectiveness in reducing coke oven emissions and their capability for production of steel quality coke.

Such regulations shall require at a minimum that coke oven batteries will not exceed 8 per centum leaking doors, 1 per centum leaking lids, 5 per centum leaking offtakes, and 16 seconds visible emissions per charge, with no exclusion for emissions during the period after the closing of self-sealing oven doors. Notwithstanding subsection (i), the compliance date for such emission standards for existing coke oven batteries shall be December 31, 1995.

(B) The Administrator shall promulgate work practice regulations under this subsection for coke oven batteries requiring, as appropriate—

(i) the use of sodium silicate (or equivalent) luting compounds, if the Administrator determines that use of sodium silicate is an effective means of emissions control and is achievable, taking into account costs and reasonable commercial warranties for doors and related equipment; and

(ii) door and jam cleaning practices.

Notwithstanding subsection (i), the compliance date for such work practice regulations for coke oven batteries shall be not later than the date 3 years after November 15, 1990.

(C) For coke oven batteries electing to qualify for an extension of the compliance date for standards promulgated under subsection (f) in accordance with subsection (i)(8), the emission standards under this subsection for coke oven batteries shall require that coke oven batteries not exceed 8 per centum leaking doors, 1 per centum leaking lids, 5 per centum leaking offtakes, and 16 seconds visible emissions per charge, with no exclusion for emissions during the period after the closing of self-sealing doors. Notwithstanding subsection (i), the compliance date for such emission standards for existing coke oven batteries seeking an extension shall be not later than the date 3 years after November 15, 1990.

(9) Sources licensed by the Nuclear Regulatory Commission

No standard for radionuclide emissions from any category or subcategory of facilities licensed by the Nuclear Regulatory Commission (or an Agreement State) is required to be promulgated under this section if the Administrator determines, by rule, and after consultation with the Nuclear Regulatory Commission, that the regulatory program established by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act [42 U.S.C. 2011 et seq.] for such category or subcategory provides an ample margin of safety to protect the public health. Nothing in this subsection shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce any standard or limitation respecting emissions of radionuclides which is more stringent than the standard or limitation in effect under section 7411 of this title or this section.

(10) Effective date

Emission standards or other regulations promulgated under this subsection shall be effective upon promulgation.

(e) Schedule for standards and review

(1) In general

The Administrator shall promulgate regulations establishing emission standards for categories and subcategories of sources initially listed for regulation pursuant to subsection (c)(1) as expeditiously as practicable, assuring that—

(A) emission standards for not less than 40 categories and subcategories (not counting coke oven batteries) shall be promulgated not later than 2 years after November 15, 1990;

(B) emission standards for coke oven batteries shall be promulgated not later than December 31, 1992;

(C) emission standards for 25 per centum of the listed categories and subcategories shall be promulgated not later than 4 years after November 15, 1990;

(D) emission standards for an additional 25 per centum of the listed categories and subcategories shall be promulgated not later than 7 years after November 15, 1990; and

(E) emission standards for all categories and subcategories shall be promulgated not later than 10 years after November 15, 1990.

(2) Priorities

In determining priorities for promulgating standards under subsection (d), the Administrator shall consider—

(A) the known or anticipated adverse effects of such pollutants on public health and the environment;

(B) the quantity and location of emissions or reasonably anticipated emissions of hazardous air pollutants that each category or subcategory will emit; and

(C) the efficiency of grouping categories or subcategories according to the pollutants emitted, or the processes or technologies used.

(3) Published schedule

Not later than 24 months after November 15, 1990, and after opportunity for comment, the Administrator shall publish a schedule establishing a date for the promulgation of emission standards for each category and subcategory of sources listed pursuant to subsection (c)(1) and (3) which shall be consistent with the requirements of paragraphs (1) and (2). The determination of priorities for the promulgation of standards pursuant to this paragraph is not a rulemaking and shall not be subject to judicial review, except that, failure to promulgate any standard pursuant to the schedule established by this paragraph shall be subject to review under section 7604 of this title.

(4) Judicial review

Notwithstanding section 7607 of this title, no action of the Administrator adding a pollutant to the list under subsection (b) or listing a source category or subcategory under subsection (c) shall be a final agency action subject to judicial review, except that any such action may be reviewed under such section 7607 of this title when the Administrator issues emission standards for such pollutant or category.

(5) Publicly owned treatment works

The Administrator shall promulgate standards pursuant to subsection (d) applicable to publicly owned treatment works (as defined in title II of the Federal Water Pollution Control Act [33 U.S.C. 1281 et seq.]) not later than 5 years after November 15, 1990.

(f) Standard to protect health and environment

(1) Report

Not later than 6 years after November 15, 1990, the Administrator shall investigate and report, after consultation with the Surgeon General and after opportunity for public comment, to Congress on—

(A) methods of calculating the risk to public health remaining, or likely to remain, from sources subject to regulation under this section after the application of standards under subsection (d);

(B) the public health significance of such estimated remaining risk and the technologically and commercially available methods and costs of reducing such risks;

(C) the actual health effects with respect to persons living in the vicinity of sources, any available epidemiological or other health studies, risks presented by background concentrations of hazardous air pollutants, any uncertainties in risk assessment methodology or other health assessment technique, and any negative health or environmental consequences to the community of efforts to reduce such risks; and

(D) recommendations as to legislation regarding such remaining risk.

(2) Emission standards

(A) If Congress does not act on any recommendation submitted under paragraph (1), the Administrator shall, within 8 years after promulgation of standards for each category or subcategory of sources pursuant to subsection (d), promulgate standards for such category or subcategory if promulgation of such standards is required in order to provide an ample margin of safety to protect public health in accordance with this section (as in effect before November 15, 1990) or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. Emission standards promulgated under this subsection shall provide an ample margin of safety to protect public health in accordance with this section (as in effect before November 15, 1990), unless the Administrator determines that a more stringent standard is necessary to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. If standards promulgated pursuant to subsection (d) and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than one in one million, the Administrator shall promulgate standards under this subsection for such source category.

(B) Nothing in subparagraph (A) or in any other provision of this section shall be construed as affecting, or applying to the Administrator's interpretation of this section, as in effect before November 15, 1990, and set forth in the Federal Register of September 14, 1989 (54 Federal Register 38044).

(C) The Administrator shall determine whether or not to promulgate such standards and, if the Administrator decides to promulgate such standards, shall promulgate the standards 8 years after promulgation of the standards under subsection (d) for each source category or subcategory concerned. In the case of categories or subcategories for which standards under subsection (d) are required to be promulgated within 2 years after November 15, 1990, the Administrator shall have 9 years after promulgation of the standards under subsection (d) to make the determination under the preceding sentence and, if required, to promulgate the standards under this paragraph.

(3) Effective date

Any emission standard established pursuant to this subsection shall become effective upon promulgation.

(4) Prohibition

No air pollutant to which a standard under this subsection applies may be emitted from any stationary source in violation of such standard, except that in the case of an existing source—

(A) such standard shall not apply until 90 days after its effective date, and

(B) the Administrator may grant a waiver permitting such source a period of up to 2 years after the effective date of a standard to comply with the standard if the Administrator finds that such period is necessary for the installation of controls and that steps will be taken during the period of the waiver to assure that the health of persons will be protected from imminent endangerment.

(5) Area sources

The Administrator shall not be required to conduct any review under this subsection or promulgate emission limitations under this subsection for any category or subcategory of area sources that is listed pursuant to subsection (c)(3) and for which an emission standard is promulgated pursuant to subsection (d)(5).

(6) Unique chemical substances

In establishing standards for the control of unique chemical substances of listed pollutants without CAS numbers under this subsection, the Administrator shall establish such standards with respect to the health and environmental effects of the substances actually emitted by sources and direct transformation byproducts of such emissions in the categories and subcategories.

(g) Modifications

(1) Offsets

(A) A physical change in, or change in the method of operation of, a major source which results in a greater than de minimis increase in actual emissions of a hazardous air pollutant shall not be considered a modification, if such increase in the quantity of actual emissions of any hazardous air pollutant from such source will be offset by an equal or greater decrease in the quantity of emissions of another hazardous air pollutant (or pollutants) from such source which is deemed more hazardous, pursuant to guidance issued by the Administrator under subparagraph (B). The owner or operator of such source shall submit a showing to the Administrator (or the State) that such increase has been offset under the preceding sentence.

(B) The Administrator shall, after notice and opportunity for comment and not later than 18 months after November 15, 1990, publish guidance with respect to implementation of this subsection. Such guidance shall include an identification, to the extent practicable, of the relative hazard to human health resulting from emissions to the ambient air of each of the pollutants listed under subsection (b) sufficient to facilitate the offset showing authorized by subparagraph (A). Such guidance shall not authorize offsets between pollutants where the increased pollutant (or more than one pollutant in a stream of pollutants) causes adverse effects to human health for which no safety threshold for exposure can be determined unless there are corresponding decreases in such types of pollutant(s).

(2) Construction, reconstruction and modifications

(A) After the effective date of a permit program under subchapter V in any State, no person may modify a major source of hazardous air pollutants in such State, unless the Administrator (or the State) determines that the maximum achievable control technology emission limitation under this section for existing sources will be met. Such determination shall be made on a case-by-case basis where no applicable emissions limitations have been established by the Administrator.

(B) After the effective date of a permit program under subchapter V in any State, no person may construct or reconstruct any major source of hazardous air pollutants, unless the Administrator (or the State) determines that the maximum achievable control technology emission limitation under this section for new sources will be met. Such determination shall be made on a case-by-case basis where no applicable emission limitations have been established by the Administrator.

(3) Procedures for modifications

The Administrator (or the State) shall establish reasonable procedures for assuring that the requirements applying to modifications under this section are reflected in the permit.

(h) Work practice standards and other requirements

(1) In general

For purposes of this section, if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of subsection (d) or (f). In the event the Administrator promulgates a design or equipment standard under this subsection, the Administrator shall include as part of such standard such requirements as will assure the proper operation and maintenance of any such element of design or equipment.

(2) Definition

For the purpose of this subsection, the phrase "not feasible to prescribe or enforce an emission standard" means any situation in which the Administrator determines that—

(A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State or local law, or

(B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

(3) Alternative standard

If after notice and opportunity for comment, the owner or operator of any source establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such pollutant achieved under the requirements of paragraph (1), the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant.

(4) Numerical standard required

Any standard promulgated under paragraph (1) shall be promulgated in terms of an emission standard whenever it is feasible to promulgate and enforce a standard in such terms.

(i) Schedule for compliance

(1) Preconstruction and operating requirements

After the effective date of any emission standard, limitation, or regulation under subsection (d), (f) or (h), no person may construct any new major source or reconstruct any existing major source subject to such emission standard, regulation or limitation unless the Administrator (or a State with a permit program approved under subchapter V) determines that such source, if properly constructed, reconstructed and operated, will comply with the standard, regulation or limitation.

(2) Special rule

Notwithstanding the requirements of paragraph (1), a new source which commences construction or reconstruction after a standard, limitation or regulation applicable to such source is proposed and before such standard, limitation or regulation is promulgated shall not be required to comply with such promulgated standard until the date 3 years after the date of promulgation if—

(A) the promulgated standard, limitation or regulation is more stringent than the standard, limitation or regulation proposed; and

(B) the source complies with the standard, limitation, or regulation as proposed during the 3-year period immediately after promulgation.

(3) Compliance schedule for existing sources

(A) After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard, except as provided in subparagraph (B) and paragraphs (4) through (8).

(B) The Administrator (or a State with a program approved under subchapter V) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) if such additional period is necessary for the installation of controls. An additional extension of up to 3 years may be added for mining waste operations, if the 4-year compliance time is insufficient to dry and cover mining waste in order to reduce emissions of any pollutant listed under subsection (b).

(4) Presidential exemption

The President may exempt any stationary source from compliance with any standard or limitation under this section for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. An exemption under this paragraph may be extended for 1 or more additional periods, each period not to exceed 2 years. The President shall report to Congress with respect to each exemption (or extension thereof) made under this paragraph.

(5) Early reduction

(A) The Administrator (or a State acting pursuant to a permit program approved under subchapter V) shall issue a permit allowing an existing source, for which the owner or operator demonstrates that the source has achieved a reduction of 90 per centum or more in emissions of hazardous air pollutants (95 per centum in the case of hazardous air pollutants which are particulates) from the source, to meet an alternative emission limitation reflecting such reduction in lieu of an emission limitation promulgated under subsection (d) for a period of 6 years from the compliance date for the otherwise applicable standard, provided that such reduction is achieved before the otherwise applicable standard under subsection (d) is first proposed. Nothing in this paragraph shall preclude a State from requiring reductions in excess of those specified in this subparagraph as a condition of granting the extension authorized by the previous sentence.

(B) An existing source which achieves the reduction referred to in subparagraph (A) after the proposal of an applicable standard but before January 1, 1994, may qualify under subparagraph (A), if the source makes an enforceable commitment to achieve such reduction before the proposal of the standard. Such commitment shall be enforceable to the same extent as a regulation under this section.

(C) The reduction shall be determined with respect to verifiable and actual emissions in a base year not earlier than calendar year 1987, provided that, there is no evidence that emissions in the base year are artificially or substantially greater than emissions in other years prior to implementation of emissions reduction measures. The Administrator may allow a source to use a baseline year of 1985 or 1986 provided that the source can demonstrate to the satisfaction of the Administrator that emissions data for the source reflects verifiable data based on information for such source, received by the Administrator prior to November 15, 1990, pursuant to an information request issued under section 7414 of this title.

(D) For each source granted an alternative emission limitation under this paragraph there shall be established by a permit issued pursuant to subchapter V an enforceable emission limitation for hazardous air pollutants reflecting the reduction which qualifies the source for an alternative emission limitation under this paragraph. An alternative emission limitation under this paragraph shall not be available with respect to standards or requirements promulgated pursuant to subsection (f) and the Administrator shall, for the purpose of determining whether a standard under subsection (f) is necessary, review emissions from sources granted an alternative emission limitation under this paragraph at the same time that other sources in the category or subcategory are reviewed.

(E) With respect to pollutants for which high risks of adverse public health effects may be associated with exposure to small quantities including, but not limited to, chlorinated dioxins and furans, the Administrator shall by regulation limit the use of offsetting reductions in emissions of other hazardous air pollutants from the source as counting toward the 90 per centum reduction in such high-risk pollutants qualifying for an alternative emissions limitation under this paragraph.

(6) Other reductions

Notwithstanding the requirements of this section, no existing source that has installed—

(A) best available control technology (as defined in section 7479(3) of this title), or

(B) technology required to meet a lowest achievable emission rate (as defined in section 7501 of this title),

prior to the promulgation of a standard under this section applicable to such source and the same pollutant (or stream of pollutants) controlled pursuant to an action described in subparagraph (A) or (B) shall be required to comply with such standard under this section until the date 5 years after the date on which such installation or reduction has been achieved, as determined by the Administrator. The Administrator may issue such rules and guidance as are necessary to implement this paragraph.

(7) Extension for new sources

A source for which construction or reconstruction is commenced after the date an emission standard applicable to such source is proposed pursuant to subsection (d) but before the date an emission standard applicable to such source is proposed pursuant to subsection (f) shall not be required to comply with the emission standard under subsection (f) until the date 10 years after the date construction or reconstruction is commenced.

(8) Coke ovens

(A) Any coke oven battery that complies with the emission limitations established under subsection (d)(8)(C), subparagraph (B), and subparagraph (C), and complies with the provisions of subparagraph (E), shall not be required to achieve emission limitations promulgated under subsection (f) until January 1, 2020.

(B)(i) Not later than December 31, 1992, the Administrator shall promulgate emission limitations for coke oven emissions from coke oven batteries. Notwithstanding paragraph (3) of this subsection, the compliance date for such emission limitations for existing coke oven batteries shall be January 1, 1998. Such emission limitations shall reflect the lowest achievable emission rate as defined in section 7501 of this title for a coke oven battery that is rebuilt or a replacement at a coke oven plant for an existing battery. Such emission limitations shall be no less stringent than—

(I) 3 per centum leaking doors (5 per centum leaking doors for six meter batteries);

(II) 1 per centum leaking lids;

(III) 4 per centum leaking offtakes; and

(IV) 16 seconds visible emissions per charge,

with an exclusion for emissions during the period after the closing of self-sealing oven doors (or the total mass emissions equivalent). The rulemaking in which such emission limitations are promulgated shall also establish an appropriate measurement methodology for determining compliance with such emission limitations, and shall establish such emission limitations in terms of an equivalent level of mass emissions reduction from a coke oven battery, unless the Administrator finds that such a mass emissions standard would not be practicable or enforceable. Such measurement methodology, to the extent it measures leaking doors, shall take into consideration alternative test methods that reflect the best technology and practices actually applied in the affected industries, and shall assure that the final test methods are consistent with the performance of such best technology and practices.

(ii) If the Administrator fails to promulgate such emission limitations under this subparagraph prior to the effective date of such emission limitations, the emission limitations applicable to coke oven batteries under this subparagraph shall be—

(I) 3 per centum leaking doors (5 per centum leaking doors for six meter batteries);

(II) 1 per centum leaking lids;

(III) 4 per centum leaking offtakes; and

(IV) 16 seconds visible emissions per charge,

or the total mass emissions equivalent (if the total mass emissions equivalent is determined to be practicable and enforceable), with no exclusion for emissions during the period after the closing of self-sealing oven doors.

(C) Not later than January 1, 2007, the Administrator shall review the emission limitations promulgated under subparagraph (B) and revise, as necessary, such emission limitations to reflect the lowest achievable emission rate as defined in section 7501 of this title at the time for a coke oven battery that is rebuilt or a replacement at a coke oven plant for an existing battery. Such emission limitations shall be no less stringent than the emission limitation promulgated under subparagraph (B). Notwithstanding paragraph (2) of this subsection, the compliance date for such emission limitations for existing coke oven batteries shall be January 1, 2010.

(D) At any time prior to January 1, 1998, the owner or operator of any coke oven battery may elect to comply with emission limitations promulgated under subsection (f) by the date such emission limitations would otherwise apply to such coke oven battery, in lieu of the emission limitations and the compliance dates provided under subparagraphs (B) and (C) of this paragraph. Any such owner or operator shall be legally bound to comply with such emission limitations promulgated under subsection (f) with respect to such coke oven battery as of January 1, 2003. If no such emission limitations have been promulgated for such coke oven battery, the Administrator shall promulgate such emission limitations in accordance with subsection (f) for such coke oven battery.

(E) Coke oven batteries qualifying for an extension under subparagraph (A) shall make available not later than January 1, 2000, to the surrounding communities the results of any risk assessment performed by the Administrator to determine the appropriate level of any emission standard established by the Administrator pursuant to subsection (f).

(F) Notwithstanding the provisions of this section, reconstruction of any source of coke oven emissions qualifying for an extension under this paragraph shall not subject such source to emission limitations under subsection (f) more stringent than those established under subparagraphs (B) and (C) until January 1, 2020. For the purposes of this subparagraph, the term ''reconstruction'' includes the replacement of existing coke oven battery capacity with new coke oven batteries of comparable or lower capacity and lower potential emissions.

(j) Equivalent emission limitation by permit

(1) Effective date

The requirements of this subsection shall apply in each State beginning on the effective date of a permit program established pursuant to subchapter V in such State, but not prior to the date 42 months after November 15, 1990.

(2) Failure to promulgate a standard

In the event that the Administrator fails to promulgate a standard for a category or subcategory of major sources by the date established pursuant to subsection (e)(1) and (3), and beginning 18 months after such date (but not prior to the effective date of a permit program under subchapter V), the owner or operator of any major source in such category or subcategory shall submit a permit application under paragraph (3) and such owner or operator shall also comply with paragraphs (5) and (6).

(3) Applications

By the date established by paragraph (2), the owner or operator of a major source subject to this subsection shall file an application for a permit. If the owner or operator of a source has submitted a timely and complete application for a permit required by this subsection, any failure to have a permit shall not be a violation of paragraph (2), unless the delay in final action is due to the failure of the applicant to timely submit information required or requested to process the application. The Administrator shall not later than 18 months after November 15, 1990, and after notice and opportunity for comment, establish requirements for applications under this subsection including a standard application form and criteria for determining in a timely manner the completeness of applications.

(4) Review and approval

Permit applications submitted under this subsection shall be reviewed and approved or disapproved according to the provisions of section 7661d of this title. In the event that the Administrator (or the State) disapproves a permit application submitted under this subsection or determines that the application is incomplete, the applicant shall have up to 6 months to revise the application to meet the objections of the Administrator (or the State).

(5) Emission limitation

The permit shall be issued pursuant to subchapter V and shall contain emission limitations for the hazardous air pollutants subject to regulation under this section and emitted by the source that the Administrator (or the State) determines, on a case-by-case basis, to be equivalent to the limitation that would apply to such source if an emission standard had been promulgated in a timely manner under subsection (d). In the alternative, if the applicable criteria are met, the permit may contain an emissions limitation established according to the provisions of subsection (i)(5). For purposes of the preceding sentence, the reduction required by subsection (i)(5)(A) shall be achieved by the date on which the relevant standard should have been promulgated under subsection (d). No such pollutant may be emitted in amounts exceeding an emission limitation contained in a permit immediately for new sources and, as expeditiously as practicable, but not later than the date 3 years after the permit is issued for existing sources or such other compliance date as would apply under subsection (i).

(6) Applicability of subsequent standards

If the Administrator promulgates an emission standard that is applicable to the major source prior to the date on which a permit application is approved, the emission limitation in the permit shall reflect the promulgated standard rather than the emission limitation determined pursuant to paragraph (5), provided that the source shall have the compliance period provided under subsection (i). If the Administrator promulgates a standard under subsection (d) that would be applicable to the source in lieu of the emission limitation established by permit under this subsection after the date on which the permit has been issued, the Administrator (or the State) shall revise such permit upon the next renewal to reflect the standard promulgated by the Administrator providing such source a reasonable time to comply, but no longer than 8 years after such standard is promulgated or 8 years after the date on which the source is first required to comply with the emissions limitation established by paragraph (5), whichever is earlier.

(k) Area source program

(1) Findings and purpose

The Congress finds that emissions of hazardous air pollutants from area sources may individually, or in the aggregate, present significant risks to public health in urban areas. Considering the large number of persons exposed and the risks of carcinogenic and other adverse health effects from hazardous air pollutants, ambient concentrations characteristic of large urban areas should be reduced to levels substantially below those currently experienced. It is the purpose of this subsection to achieve a substantial reduction in emissions of hazardous air pollutants from area sources and an equivalent reduction in the public health risks associated with such sources including a reduction of not less than 75 per centum in the incidence of cancer attributable to emissions from such sources.

(2) Research program

The Administrator shall, after consultation with State and local air pollution control officials, conduct a program of research with respect to sources of hazardous air pollutants in urban areas and shall include within such program—

(A) ambient monitoring for a broad range of hazardous air pollutants (including, but not limited to, volatile organic compounds, metals, pesticides and products of incomplete combustion) in a representative number of urban locations;

(B) analysis to characterize the sources of such pollution with a focus on area sources and the contribution that such sources make to public health risks from hazardous air pollutants; and

(C) consideration of atmospheric transformation and other factors which can elevate public health risks from such pollutants.

Health effects considered under this program shall include, but not be limited to, carcinogenicity, mutagenicity, teratogenicity, neurotoxicity, reproductive dysfunction and other acute and chronic effects including the role of such pollutants as precursors of ozone or acid aerosol formation. The Administrator shall report the preliminary results of such research not later than 3 years after November 15, 1990.

(3) National strategy

(A) Considering information collected pursuant to the monitoring program authorized by paragraph (2), the Administrator shall, not later than 5 years after November 15, 1990, and after notice and opportunity for public comment, prepare and transmit to the Congress a comprehensive strategy to control emissions of hazardous air pollutants from area sources in urban areas.

(B) The strategy shall—

(i) identify not less than 30 hazardous air pollutants which, as the result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas and that are or will be listed pursuant to subsection (b), and

(ii) identify the source categories or subcategories emitting such pollutants that are or will be listed pursuant to subsection (c). When identifying categories and subcategories of sources under this subparagraph, the Administrator shall assure that sources accounting for 90 per centum or more of the aggregate emissions of each of the 30 identified hazardous air pollutants are subject to standards pursuant to subsection (d).

(C) The strategy shall include a schedule of specific actions to substantially reduce the public health risks posed by the release of hazardous air pollutants from area sources that will be implemented by the Administrator under the authority of this or other laws (including, but not limited to, the Toxic Substances Control Act [15 U.S.C. 2601 et seq.], the Federal Insecticide, Fungicide and Rodenticide Act [7 U.S.C. 136 et seq.] and the Resource Conservation and Recovery Act [42 U.S.C. 6901 et seq.]) or by the States. The strategy shall achieve a reduction in the incidence of cancer attributable to exposure to hazardous air pollutants emitted by stationary sources of not less than 75 per centum, considering control of emissions of hazardous air pollutants from all stationary sources and resulting from measures implemented by the Administrator or by the States under this or other laws.

(D) The strategy may also identify research needs in monitoring, analytical methodology, modeling or pollution control techniques and recommendations for changes in law that would further the goals and objectives of this subsection.

(E) Nothing in this subsection shall be interpreted to preclude or delay implementation of actions with respect to area sources of hazardous air pollutants under consideration pursuant to this or any other law and that may be promulgated before the strategy is prepared.

(F) The Administrator shall implement the strategy as expeditiously as practicable assuring that all sources are in compliance with all requirements not later than 9 years after November 15, 1990.

(G) As part of such strategy the Administrator shall provide for ambient monitoring and emissions modeling in urban areas as appropriate to demonstrate that the goals and objectives of the strategy are being met.

(4) Areawide activities

In addition to the national urban air toxics strategy authorized by paragraph (3), the Administrator shall also encourage and support areawide strategies developed by State or local air pollution control agencies that are intended to reduce risks from emissions by area sources within a particular urban area. From the funds available for grants under this section, the Administrator shall set aside not less than 10 per centum to support areawide strategies addressing hazardous air pollutants emitted by area sources and shall award such funds on a demonstration basis to those States with innovative and effective strategies. At the request of State or local air pollution control officials, the Administrator shall prepare guidelines for control technologies or management practices which may be applicable to various categories or subcategories of area sources.

(5) Report

The Administrator shall report to the Congress at intervals not later than 8 and 12 years after November 15, 1990, on actions taken under this subsection and other parts of this chapter to reduce the risk to public health posed by the release of hazardous air pollutants from area sources. The reports shall also identify specific metropolitan areas that continue to experience high risks to public health as the result of emissions from area sources.

(*l*) State programs

(1) In general

Each State may develop and submit to the Administrator for approval a program for the implementation and enforcement (including a review of enforcement delegations previously granted) of emission standards and other requirements for air pollutants subject to this section or requirements for the prevention and mitigation of accidental releases pursuant to subsection (r). A program submitted by a State under this subsection may provide for partial or complete delegation of the Administrator's authorities and responsibilities to implement and enforce emissions standards and prevention requirements but shall not include authority to set standards less stringent than those promulgated by the Administrator under this chapter.

(2) Guidance

Not later than 12 months after November 15, 1990, the Administrator shall publish guidance that would be useful to the States in developing programs for submittal under this subsection. The guidance shall also provide for the registration of all facilities producing, processing, handling or storing any substance listed pursuant to subsection (r) in amounts greater than the threshold quantity. The Administrator shall include as an element in such guidance an optional program begun in 1986 for the review of high-risk point sources of air pollutants including, but not limited to, hazardous air pollutants listed pursuant to subsection (b).

(3) Technical assistance

The Administrator shall establish and maintain an air toxics clearinghouse and center to provide technical information and assistance to State and local agencies and, on a cost recovery basis, to others on control technology, health and ecological risk assessment, risk analysis, ambient monitoring and modeling, and emissions measurement and monitoring. The Administrator shall use the authority of section 7403 of this title to examine methods for preventing, measuring, and controlling emissions and evaluating associated health and ecological risks. Where appropriate, such activity shall be conducted with not-for-profit organizations. The Administrator may conduct research on methods for preventing, measuring and controlling emissions and evaluating associated health and environment risks. All information collected under this paragraph shall be available to the public.

(4) Grants

Upon application of a State, the Administrator may make grants, subject to such terms and conditions as the Administrator deems appropriate, to such State for the purpose of assisting the State in developing and implementing a program for submittal and approval under this subsection. Programs assisted under this paragraph may include program elements addressing air pollutants or extremely hazardous substances other than those specifically subject to this section. Grants under this paragraph may include support for high-risk point source review as provided in paragraph (2) and support for the development and implementation of areawide area source programs pursuant to subsection (k).

(5) Approval or disapproval

Not later than 180 days after receiving a program submitted by a State, and after notice and opportunity for public comment, the Administrator shall either approve or disapprove such program. The Administrator shall disapprove any program submitted by a State, if the Administrator determines that—

(A) the authorities contained in the program are not adequate to assure compliance by all sources within the State with each applicable standard, regulation or requirement established by the Administrator under this section;

(B) adequate authority does not exist, or adequate resources are not available, to implement the program;

(C) the schedule for implementing the program and assuring compliance by affected sources is not sufficiently expeditious; or

(D) the program is otherwise not in compliance with the guidance issued by the Administrator under paragraph (2) or is not likely to satisfy, in whole or in part, the objectives of this chapter.

If the Administrator disapproves a State program, the Administrator shall notify the State of any revisions or modifications necessary to obtain approval. The State may revise and resubmit the proposed program for review and approval pursuant to the provisions of this subsection.

(6) Withdrawal

Whenever the Administrator determines, after public hearing, that a State is not administering and enforcing a program approved pursuant to this subsection in accordance with the guidance published pursuant to paragraph (2) or the requirements of paragraph (5), the Administrator shall so notify the State and, if action which will assure prompt compliance is not taken within 90 days, the Administrator shall withdraw approval of the program. The Administrator shall not withdraw approval of any program unless the State shall have been notified and the reasons for withdrawal shall have been stated in writing and made public.

(7) Authority to enforce

Nothing in this subsection shall prohibit the Administrator from enforcing any applicable emission standard or requirement under this section.

(8) Local program

The Administrator may, after notice and opportunity for public comment, approve a program developed and submitted by a local air pollution control agency (after consultation with the State) pursuant to this subsection and any such agency implementing an approved program may take any action authorized to be taken by a State under this section.

(9) Permit authority

Nothing in this subsection shall affect the authorities and obligations of the Administrator or the State under subchapter V.

(m) Atmospheric deposition to Great Lakes and coastal waters

(1) Deposition assessment

The Administrator, in cooperation with the Under Secretary of Commerce for Oceans and

Atmosphere, shall conduct a program to identify and assess the extent of atmospheric deposition of hazardous air pollutants (and in the discretion of the Administrator, other air pollutants) to the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters. As part of such program, the Administrator shall—

(A) monitor the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters, including monitoring of the Great Lakes through the monitoring network established pursuant to paragraph (2) of this subsection and designing and deploying an atmospheric monitoring network for coastal waters pursuant to paragraph (4);

(B) investigate the sources and deposition rates of atmospheric deposition of air pollutants (and their atmospheric transformation precursors);

(C) conduct research to develop and improve monitoring methods and to determine the relative contribution of atmospheric pollutants to total pollution loadings to the Great Lakes, the Chesapeake Bay, Lake Champlain, and coastal waters;

(D) evaluate any adverse effects to public health or the environment caused by such deposition (including effects resulting from indirect exposure pathways) and assess the contribution of such deposition to violations of water quality standards established pursuant to the Federal Water Pollution Control Act [33 U.S.C. 1251 et seq.] and drinking water standards established pursuant to the Safe Drinking Water Act [42 U.S.C. 300f et seq.]; and

(E) sample for such pollutants in biota, fish, and wildlife of the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters and characterize the sources of such pollutants.

(2) Great Lakes monitoring network

The Administrator shall oversee, in accordance with Annex 15 of the Great Lakes Water Quality Agreement, the establishment and operation of a Great Lakes atmospheric deposition network to monitor atmospheric deposition of hazardous air pollutants (and in the Administrator's discretion, other air pollutants) to the Great Lakes.

(A) As part of the network provided for in this paragraph, and not later than December 31, 1991, the Administrator shall establish in each of the 5 Great Lakes at least 1 facility capable of monitoring the atmospheric deposition of hazardous air pollutants in both dry and wet conditions.

(B) The Administrator shall use the data provided by the network to identify and track the movement of hazardous air pollutants through the Great Lakes, to determine the portion of water pollution loadings attributable to atmospheric deposition of such pollutants, and to support development of remedial action plans and other management plans as required by the Great Lakes Water Quality Agreement.

(C) The Administrator shall assure that the data collected by the Great Lakes atmospheric deposition monitoring network is in a format compatible with databases sponsored by the International Joint Commission, Canada, and the several States of the Great Lakes region.

(3) Monitoring for the Chesapeake Bay and Lake Champlain

The Administrator shall establish at the Chesapeake Bay and Lake Champlain atmospheric deposition stations to monitor deposition of hazardous air pollutants (and in the Administrator's discretion, other air pollutants) within the Chesapeake Bay and Lake Champlain watersheds. The Administrator shall determine the role of air deposition in the pollutant loadings of the Chesapeake Bay and Lake Champlain, investigate the sources of air pollutants deposited in the watersheds, evaluate the health and environmental effects of such pollutant loadings, and shall sample such pollutants in biota, fish and wildlife within the watersheds, as necessary to characterize such effects.

(4) Monitoring for coastal waters

The Administrator shall design and deploy atmospheric deposition monitoring networks for coastal waters and their watersheds and shall make any information collected through such networks available to the public. As part of this effort, the Administrator shall conduct research to develop and improve deposition monitoring methods, and to determine the relative contribution of atmospheric pollutants to pollutant loadings. For purposes of this subsection, ''coastal waters'' shall mean estuaries selected pursuant to section 320(a)(2)(A) of the Federal Water Pollution Control Act [33 U.S.C. 1330(a)(2)(A)] or listed pursuant to section 320(a)(2)(B) of such Act [33 U.S.C. 1330(a)(2)(B)] or estuarine research reserves designated pursuant to section 1461 of title 16.

(5) Report

Within 3 years of November 15, 1990, and biennially thereafter, the Administrator, in cooperation with the Under Secretary of Commerce for Oceans and Atmosphere, shall submit to the Congress a report on the results of any monitoring, studies, and investigations conducted pursuant to this subsection. Such report shall include, at a minimum, an assessment of—

(A) the contribution of atmospheric deposition to pollution loadings in the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters;

(B) the environmental and public health effects of any pollution which is attributable to atmospheric deposition to the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters;

(C) the source or sources of any pollution to the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters which is attributable to atmospheric deposition;

(D) whether pollution loadings in the Great Lakes, the Chesapeake Bay, Lake Champlain or coastal waters cause or contribute to exceedances of drinking water standards pursuant to the Safe Drinking

Water Act [42 U.S.C. 300f et seq.] or water quality standards pursuant to the Federal Water Pollution Control Act [33 U.S.C. 1251 et seq.] or, with respect to the Great Lakes, exceedances of the specific objectives of the Great Lakes Water Quality Agreement; and

(E) a description of any revisions of the requirements, standards, and limitations pursuant to this chapter and other applicable Federal laws as are necessary to assure protection of human health and the environment.

(6) Additional regulation

As part of the report to Congress, the Administrator shall determine whether the other provisions of this section are adequate to prevent serious adverse effects to public health and serious or widespread environmental effects, including such effects resulting from indirect exposure pathways, associated with atmospheric deposition to the Great Lakes, the Chesapeake Bay, Lake Champlain and coastal waters of hazardous air pollutants (and their atmospheric transformation products). The Administrator shall take into consideration the tendency of such pollutants to bioaccumulate. Within 5 years after November 15, 1990, the Administrator shall, based on such report and determination, promulgate, in accordance with this section, such further emission standards or control measures as may be necessary and appropriate to prevent such effects, including effects due to bioaccumulation and indirect exposure pathways. Any requirements promulgated pursuant to this paragraph with respect to coastal waters shall only apply to the coastal waters of the States which are subject to section 7627(a) of this title.

(n) Other provisions

(1) Electric utility steam generating units

(A) The Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) after imposition of the requirements of this chapter. The Administrator shall report the results of this study to the Congress within 3 years after November 15, 1990. The Administrator shall develop and describe in the Administrator's report to Congress alternative control strategies for emissions which may warrant regulation under this section. The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph.

(B) The Administrator shall conduct, and transmit to the Congress not later than 4 years after November 15, 1990, a study of mercury emissions from electric utility steam generating units, municipal waste combustion units, and other sources, including area sources. Such study shall consider the rate and mass of such emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies.

(C) The National Institute of Environmental Health Sciences shall conduct, and transmit to the Congress not later than 3 years after November 15, 1990, a study to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur. Such study shall include a threshold for mercury concentrations in the tissue of fish which may be consumed (including consumption by sensitive populations) without adverse effects to public health.

(2) Coke oven production technology study

(A) The Secretary of the Department of Energy and the Administrator shall jointly undertake a 6-year study to assess coke oven production emission control technologies and to assist in the development and commercialization of technically practicable and economically viable control technologies which have the potential to significantly reduce emissions of hazardous air pollutants from coke oven production facilities. In identifying control technologies, the Secretary and the Administrator shall consider the range of existing coke oven operations and battery design and the availability of sources of materials for such coke ovens as well as alternatives to existing coke oven production design.

(B) The Secretary and the Administrator are authorized to enter into agreements with persons who propose to develop, install and operate coke production emission control technologies which have the potential for significant emissions reductions of hazardous air pollutants provided that Federal funds shall not exceed 50 per centum of the cost of any project assisted pursuant to this paragraph.

(C) On completion of the study, the Secretary shall submit to Congress a report on the results of the study and shall make recommendations to the Administrator identifying practicable and economically viable control technologies for coke oven production facilities to reduce residual risks remaining after implementation of the standard under subsection (d).

(D) There are authorized to be appropriated $5,000,000 for each of the fiscal years 1992 through 1997 to carry out the program authorized by this paragraph.

(3) Publicly owned treatment works

The Administrator may conduct, in cooperation with the owners and operators of publicly owned treatment works, studies to characterize emissions of hazardous air pollutants emitted by such facilities, to identify industrial, commercial and residential discharges that contribute to such emissions and to demonstrate control measures for such emissions. When promulgating any standard under this section applicable to publicly owned treatment works, the Administrator may provide for control measures that include pretreatment of discharges causing emissions of hazardous air pollutants and process or product substitutions or limitations that may be effective in reducing such emissions. The Administrator may prescribe uniform sampling, modeling and risk assessment methods for use in implementing this subsection.

(4) Oil and gas wells; pipeline facilities

(A) Notwithstanding the provisions of subsection (a), emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

(B) The Administrator shall not list oil and gas production wells (with its associated equipment) as an area source category under subsection (c), except that the Administrator may establish an area source category for oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million, if the Administrator determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health.

(5) Hydrogen sulfide

The Administrator is directed to assess the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natural gas resources. To the extent practicable, the assessment shall build upon and not duplicate work conducted for an assessment pursuant to section 8002(m) of the Solid Waste Disposal Act [42 U.S.C. 6982(m)] and shall reflect consultation with the States. The assessment shall include a review of existing State and industry control standards, techniques and enforcement. The Administrator shall report to the Congress within 24 months after November 15, 1990, with the findings of such assessment, together with any recommendations, and shall, as appropriate, develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment, based on the findings of such assessment, using authorities under this chapter including sections[3] 7411 of this title and this section.

(6) Hydrofluoric acid

Not later than 2 years after November 15, 1990, the Administrator shall, for those regions of the country which do not have comprehensive health and safety regulations with respect to hydrofluoric acid, complete a study of the potential hazards of hydrofluoric acid and the uses of hydrofluoric acid in industrial and commercial applications to public health and the environment considering a range of events including worst-case accidental releases and shall make recommendations to the Congress for the reduction of such hazards, if appropriate.

(7) RCRA facilities

In the case of any category or subcategory of sources the air emissions of which are regulated under subtitle C of the Solid Waste Disposal Act [42 U.S.C. 6921 et seq.], the Administrator shall take into account any regulations of such emissions which are promulgated under such subtitle and shall, to the maximum extent practicable and consistent with the provisions of this section, ensure that the requirements of such subtitle and this section are consistent.

(*o*) National Academy of Sciences study

(1) Request of the Academy

Within 3 months of November 15, 1990, the Administrator shall enter into appropriate arrangements with the National Academy of Sciences to conduct a review of—

(A) risk assessment methodology used by the Environmental Protection Agency to determine the carcinogenic risk associated with exposure to hazardous air pollutants from source categories and subcategories subject to the requirements of this section; and

(B) improvements in such methodology.

(2) Elements to be studied

In conducting such review, the National Academy of Sciences should consider, but not be limited to, the following—

(A) the techniques used for estimating and describing the carcinogenic potency to humans of hazardous air pollutants; and

(B) the techniques used for estimating exposure to hazardous air pollutants (for hypothetical and actual maximally exposed individuals as well as other exposed individuals).

(3) Other health effects of concern

To the extent practicable, the Academy shall evaluate and report on the methodology for assessing the risk of adverse human health effects other than cancer for which safe thresholds of exposure may not exist, including, but not limited to, inheritable genetic mutations, birth defects, and reproductive dysfunctions.

(4) Report

A report on the results of such review shall be submitted to the Senate Committee on Environment and Public Works, the House Committee on Energy and Commerce, the Risk Assessment and Management Commission established by section 303 of the Clean Air Act Amendments of 1990 and the Administrator not later than 30 months after November 15, 1990.

(5) Assistance

The Administrator shall assist the Academy in gathering any information the Academy deems necessary to carry out this subsection. The Administrator may use any authority under this chapter to obtain information from any person, and to require any person to conduct tests, keep and produce records, and make reports respecting research or other activities conducted by such person as necessary to carry out this subsection.

(6) Authorization

Of the funds authorized to be appropriated to the Administrator by this chapter, such

[3] So in original. Probably should be "section".

amounts as are required shall be available to carry out this subsection.

(7) Guidelines for carcinogenic risk assessment

The Administrator shall consider, but need not adopt, the recommendations contained in the report of the National Academy of Sciences prepared pursuant to this subsection and the views of the Science Advisory Board, with respect to such report. Prior to the promulgation of any standard under subsection (f), and after notice and opportunity for comment, the Administrator shall publish revised Guidelines for Carcinogenic Risk Assessment or a detailed explanation of the reasons that any recommendations contained in the report of the National Academy of Sciences will not be implemented. The publication of such revised Guidelines shall be a final Agency action for purposes of section 7607 of this title.

(p) Mickey Leland National Urban Air Toxics Research Center

(1) Establishment

The Administrator shall oversee the establishment of a National Urban Air Toxics Research Center, to be located at a university, a hospital, or other facility capable of undertaking and maintaining similar research capabilities in the areas of epidemiology, oncology, toxicology, pulmonary medicine, pathology, and biostatistics. The center shall be known as the Mickey Leland National Urban Air Toxics Research Center. The geographic site of the National Urban Air Toxics Research Center should be further directed to Harris County, Texas, in order to take full advantage of the well developed scientific community presence on-site at the Texas Medical Center as well as the extensive data previously compiled for the comprehensive monitoring system currently in place.

(2) Board of Directors

The National Urban Air Toxics Research Center shall be governed by a Board of Directors to be comprised of 9 members, the appointment of which shall be allocated pro rata among the Speaker of the House, the Majority Leader of the Senate and the President. The members of the Board of Directors shall be selected based on their respective academic and professional backgrounds and expertise in matters relating to public health, environmental pollution and industrial hygiene. The duties of the Board of Directors shall be to determine policy and research guidelines, submit views from center sponsors and the public and issue periodic reports of center findings and activities.

(3) Scientific Advisory Panel

The Board of Directors shall be advised by a Scientific Advisory Panel, the 13 members of which shall be appointed by the Board, and to include eminent members of the scientific and medical communities. The Panel membership may include scientists with relevant experience from the National Institute of Environmental Health Sciences, the Center for Disease Control, the Environmental Protection Agency, the National Cancer Institute, and others, and the Panel shall conduct peer review and evaluate research results. The Panel shall assist the Board in developing the research agenda, reviewing proposals and applications, and advise on the awarding of research grants.

(4) Funding

The center shall be established and funded with both Federal and private source funds.

(q) Savings provision

(1) Standards previously promulgated

Any standard under this section in effect before the date of enactment of the Clean Air Act Amendments of 1990 [November 15, 1990] shall remain in force and effect after such date unless modified as provided in this section before the date of enactment of such Amendments or under such Amendments. Except as provided in paragraph (4), any standard under this section which has been promulgated, but has not taken effect, before such date shall not be affected by such Amendments unless modified as provided in this section before such date or under such Amendments. Each such standard shall be reviewed and, if appropriate, revised, to comply with the requirements of subsection (d) within 10 years after the date of enactment of the Clean Air Act Amendments of 1990. If a timely petition for review of any such standard under section 7607 of this title is pending on such date of enactment, the standard shall be upheld if it complies with this section as in effect before that date. If any such standard is remanded to the Administrator, the Administrator may in the Administrator's discretion apply either the requirements of this section, or those of this section as in effect before the date of enactment of the Clean Air Act Amendments of 1990.

(2) Special rule

Notwithstanding paragraph (1), no standard shall be established under this section, as amended by the Clean Air Act Amendments of 1990, for radionuclide emissions from (A) elemental phosphorous plants, (B) grate calcination elemental phosphorous plants, (C) phosphogypsum stacks, or (D) any subcategory of the foregoing. This section, as in effect prior to the date of enactment of the Clean Air Act Amendments of 1990 [November 15, 1990], shall remain in effect for radionuclide emissions from such plants and stacks.

(3) Other categories

Notwithstanding paragraph (1), this section, as in effect prior to the date of enactment of the Clean Air Act Amendments of 1990 [November 15, 1990], shall remain in effect for radionuclide emissions from non-Department of Energy Federal facilities that are not licensed by the Nuclear Regulatory Commission, coal-fired utility and industrial boilers, underground uranium mines, surface uranium mines, and disposal of uranium mill tailings piles, unless the Administrator, in the Administrator's discretion, applies the requirements of this section as modified by the Clean Air Act Amendments of 1990 to such sources of radionuclides.

(4) Medical facilities

Notwithstanding paragraph (1), no standard promulgated under this section prior to November 15, 1990, with respect to medical research or treatment facilities shall take effect for two years following November 15, 1990, unless the Administrator makes a determination pursuant to a rulemaking under subsection (d)(9). If the Administrator determines that the regulatory program established by the Nuclear Regulatory Commission for such facilities does not provide an ample margin of safety to protect public health, the requirements of this section shall fully apply to such facilities. If the Administrator determines that such regulatory program does provide an ample margin of safety to protect the public health, the Administrator is not required to promulgate a standard under this section for such facilities, as provided in subsection (d)(9).

(r) Prevention of accidental releases

(1) Purpose and general duty

It shall be the objective of the regulations and programs authorized under this subsection to prevent the accidental release and to minimize the consequences of any such release of any substance listed pursuant to paragraph (3) or any other extremely hazardous substance. The owners and operators of stationary sources producing, processing, handling or storing such substances have a general duty in the same manner and to the same extent as section 654 of title 29 to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur. For purposes of this paragraph, the provisions of section 7604 of this title shall not be available to any person or otherwise be construed to be applicable to this paragraph. Nothing in this section shall be interpreted, construed, implied or applied to create any liability or basis for suit for compensation for bodily injury or any other injury or property damages to any person which may result from accidental releases of such substances.

(2) Definitions

(A) The term ''accidental release'' means an unanticipated emission of a regulated substance or other extremely hazardous substance into the ambient air from a stationary source.

(B) The term ''regulated substance'' means a substance listed under paragraph (3).

(C) The term ''stationary source'' means any buildings, structures, equipment, installations or substance emitting stationary activities (i) which belong to the same industrial group, (ii) which are located on one or more contiguous properties, (iii) which are under the control of the same person (or persons under common control), and (iv) from which an accidental release may occur.

(D) The term ''retail facility'' means a stationary source at which more than one-half of the income is obtained from direct sales to end users or at which more than one-half of the fuel sold, by volume, is sold through a cylinder exchange program.

(3) List of substances

The Administrator shall promulgate not later than 24 months after November 15, 1990, an initial list of 100 substances which, in the case of an accidental release, are known to cause or may reasonably be anticipated to cause death, injury, or serious adverse effects to human health or the environment. For purposes of promulgating such list, the Administrator shall use, but is not limited to, the list of extremely hazardous substances published under the Emergency Planning and Community Right-to-Know[4] Act of 1986 [42 U.S.C. 11001 et seq.], with such modifications as the Administrator deems appropriate. The initial list shall include chlorine, anhydrous ammonia, methyl chloride, ethylene oxide, vinyl chloride, methyl isocyanate, hydrogen cyanide, ammonia, hydrogen sulfide, toluene diisocyanate, phosgene, bromine, anhydrous hydrogen chloride, hydrogen fluoride, anhydrous sulfur dioxide, and sulfur trioxide. The initial list shall include at least 100 substances which pose the greatest risk of causing death, injury, or serious adverse effects to human health or the environment from accidental releases. Regulations establishing the list shall include an explanation of the basis for establishing the list. The list may be revised from time to time by the Administrator on the Administrator's own motion or by petition and shall be reviewed at least every 5 years. No air pollutant for which a national primary ambient air quality standard has been established shall be included on any such list. No substance, practice, process, or activity regulated under subchapter VI shall be subject to regulations under this subsection. The Administrator shall establish procedures for the addition and deletion of substances from the list established under this paragraph consistent with those applicable to the list in subsection (b).

(4) Factors to be considered

In listing substances under paragraph (3), the Administrator—

(A) shall consider—

(i) the severity of any acute adverse health effects associated with accidental releases of the substance;

(ii) the likelihood of accidental releases of the substance; and

(iii) the potential magnitude of human exposure to accidental releases of the substance; and

(B) shall not list a flammable substance when used as a fuel or held for sale as a fuel at a retail facility under this subsection solely because of the explosive or flammable properties of the substance, unless a fire or explosion caused by the substance will result in acute adverse health effects from human exposure to the substance, including the unburned fuel or its combustion byproducts, other than those caused by the heat of the fire or impact of the explosion.

[4] So in original. Probably should be ''Right-To-Know''.

(5) Threshold quantity

At the time any substance is listed pursuant to paragraph (3), the Administrator shall establish by rule, a threshold quantity for the substance, taking into account the toxicity, reactivity, volatility, dispersibility, combustibility, or flammability of the substance and the amount of the substance which, as a result of an accidental release, is known to cause or may reasonably be anticipated to cause death, injury or serious adverse effects to human health for which the substance was listed. The Administrator is authorized to establish a greater threshold quantity for, or to exempt entirely, any substance that is a nutrient used in agriculture when held by a farmer.

(6) Chemical Safety Board

(A) There is hereby established an independent safety board to be known as the Chemical Safety and Hazard Investigation Board.

(B) The Board shall consist of 5 members, including a Chairperson, who shall be appointed by the President, by and with the advice and consent of the Senate. Members of the Board shall be appointed on the basis of technical qualification, professional standing, and demonstrated knowledge in the fields of accident reconstruction, safety engineering, human factors, toxicology, or air pollution regulation. The terms of office of members of the Board shall be 5 years. Any member of the Board, including the Chairperson, may be removed for inefficiency, neglect of duty, or malfeasance in office. The Chairperson shall be the Chief Executive Officer of the Board and shall exercise the executive and administrative functions of the Board.

(C) The Board shall—

(i) investigate (or cause to be investigated), determine and report to the public in writing the facts, conditions, and circumstances and the cause or probable cause of any accidental release resulting in a fatality, serious injury or substantial property damages;

(ii) issue periodic reports to the Congress, Federal, State and local agencies, including the Environmental Protection Agency and the Occupational Safety and Health Administration, concerned with the safety of chemical production, processing, handling and storage, and other interested persons recommending measures to reduce the likelihood or the consequences of accidental releases and proposing corrective steps to make chemical production, processing, handling and storage as safe and free from risk of injury as is possible and may include in such reports proposed rules or orders which should be issued by the Administrator under the authority of this section or the Secretary of Labor under the Occupational Safety and Health Act [29 U.S.C. 651 et seq.] to prevent or minimize the consequences of any release of substances that may cause death, injury or other serious adverse effects on human health or substantial property damage as the result of an accidental release; and

(iii) establish by regulation requirements binding on persons for reporting accidental releases into the ambient air subject to the Board's investigatory jurisdiction. Reporting releases to the National Response Center, in lieu of the Board directly, shall satisfy such regulations. The National Response Center shall promptly notify the Board of any releases which are within the Board's jurisdiction.

(D) The Board may utilize the expertise and experience of other agencies.

(E) The Board shall coordinate its activities with investigations and studies conducted by other agencies of the United States having a responsibility to protect public health and safety. The Board shall enter into a memorandum of understanding with the National Transportation Safety Board to assure coordination of functions and to limit duplication of activities which shall designate the National Transportation Safety Board as the lead agency for the investigation of releases which are transportation related. The Board shall not be authorized to investigate marine oil spills, which the National Transportation Safety Board is authorized to investigate. The Board shall enter into a memorandum of understanding with the Occupational Safety and Health Administration so as to limit duplication of activities. In no event shall the Board forego an investigation where an accidental release causes a fatality or serious injury among the general public, or had the potential to cause substantial property damage or a number of deaths or injuries among the general public.

(F) The Board is authorized to conduct research and studies with respect to the potential for accidental releases, whether or not an accidental release has occurred, where there is evidence which indicates the presence of a potential hazard or hazards. To the extent practicable, the Board shall conduct such studies in cooperation with other Federal agencies having emergency response authorities, State and local governmental agencies and associations and organizations from the industrial, commercial, and nonprofit sectors.

(G) No part of the conclusions, findings, or recommendations of the Board relating to any accidental release or the investigation thereof shall be admitted as evidence or used in any action or suit for damages arising out of any matter mentioned in such report.

(H) Not later than 18 months after November 15, 1990, the Board shall publish a report accompanied by recommendations to the Administrator on the use of hazard assessments in preventing the occurrence and minimizing the consequences of accidental releases of extremely hazardous substances. The recommendations shall include a list of extremely hazardous substances which are not regulated substances (including threshold quantities for such substances) and categories of stationary sources for which hazard assessments would be an appropriate measure to aid in the prevention of accidental releases and to minimize the consequences of those releases that do occur. The recommendations shall also include a description of the information and analysis which would be appropriate to include in any hazard assessment. The Board shall also make recommendations with respect to the role of risk management plans as required by paragraph (8)(B)[5] in preventing accidental releases. The Board may from time to time review and revise its recommendations under this subparagraph.

(I) Whenever the Board submits a recommendation with respect to accidental releases to the Administrator, the Administrator shall respond to such recommendation formally and in writing not later than 180 days after receipt thereof. The response to the Board's recommendation by the Administrator shall indicate whether the Administrator will—

(i) initiate a rulemaking or issue such orders as are necessary to implement the recommendation in full or in part, pursuant to any timetable contained in the recommendation;[6]

(ii) decline to initiate a rulemaking or issue orders as recommended.

Any determination by the Administrator not to implement a recommendation of the Board or to implement a recommendation only in part, including any variation from the schedule contained in the recommendation, shall be accompanied by a statement from the Administrator setting forth the reasons for such determination.

(J) The Board may make recommendations with respect to accidental releases to the Secretary of Labor. Whenever the Board submits such recommendation, the Secretary shall respond to such recommendation formally and in writing not later than 180 days after receipt thereof. The response to the Board's recommendation by the Administrator[7] shall indicate whether the Secretary will—

(i) initiate a rulemaking or issue such orders as are necessary to implement the recommendation in full or in part, pursuant to any timetable contained in the recommendation;[6]

(ii) decline to initiate a rulemaking or issue orders as recommended.

Any determination by the Secretary not to implement a recommendation or to implement a recommendation only in part, including any variation from the schedule contained in the recommendation, shall be accompanied by a statement from the Secretary setting forth the reasons for such determination.

(K) Within 2 years after November 15, 1990, the Board shall issue a report to the Administrator of the Environmental Protection Agency and to the Administrator of the Occupational Safety and Health Administration recommending the adoption of regulations for the preparation of risk management plans and general requirements for the prevention of accidental releases of regulated substances into the ambient air (including recommendations for listing substances under paragraph (3)) and for the mitigation of the potential adverse effect on human health or the environment as a result of accidental releases which should be applicable to any stationary source handling any regulated substance in more than threshold amounts. The Board may include proposed rules or orders which should be issued by the Administrator under authority of this subsection or by the Secretary of Labor under the Occupational Safety and Health Act [29 U.S.C. 651 et seq.]. Any such recommendations shall be specific and shall identify the regulated substance or class of regulated substances (or other substances) to which the recommendations apply. The Administrator shall consider such recommendations before promulgating regulations required by paragraph (7)(B).

(L) The Board, or upon authority of the Board, any member thereof, any administrative law judge employed by or assigned to the Board, or any officer or employee duly designated by the Board, may for the purpose of carrying out duties authorized by subparagraph (C)—

(i) hold such hearings, sit and act at such times and places, administer such oaths, and require by subpoena or otherwise attendance and testimony of such witnesses and the production of evidence and may require by order that any person engaged in the production, processing, handling, or storage of extremely hazardous substances submit written reports and responses to requests and questions within such time and in such form as the Board may require; and

(ii) upon presenting appropriate credentials and a written notice of inspection authority, enter any property where an accidental release causing a fatality, serious injury or substantial property damage has occurred and do all things therein necessary for a proper investigation pursuant to subparagraph (C) and inspect at reasonable times records, files, papers, processes, controls, and facilities and take such samples as are relevant to such investigation.

Whenever the Administrator or the Board conducts an inspection of a facility pursuant to this subsection, employees and their representatives shall have the same rights to participate in such inspections as provided in the Occupational Safety and Health Act [29 U.S.C. 651 et seq.].

(M) In addition to that described in subparagraph (L), the Board may use any information gathering authority of the Administrator under this chapter, including the subpoena power provided in section 7607(a)(1) of this title.

(N) The Board is authorized to establish such procedural and administrative rules as are necessary to the exercise of its functions and duties. The Board is authorized without regard to section 6101 of title 41 to enter into contracts, leases, cooperative agreements or other transactions as may be necessary in the conduct of the duties and functions of the Board with any other agency, institution, or person.

(O) After the effective date of any reporting requirement promulgated pursuant to sub-

[5] So in original. Probably should be paragraph "(7)(B)".

[6] So in original. The word "or" probably should appear.

[7] So in original. The word "Administrator" probably should be "Secretary".

paragraph (C)(iii) it shall be unlawful for any person to fail to report any release of any extremely hazardous substance as required by such subparagraph. The Administrator is authorized to enforce any regulation or requirements established by the Board pursuant to subparagraph (C)(iii) using the authorities of sections 7413 and 7414 of this title. Any request for information from the owner or operator of a stationary source made by the Board or by the Administrator under this section shall be treated, for purposes of sections 7413, 7414, 7416, 7420, 7603, 7604 and 7607 of this title and any other enforcement provisions of this chapter, as a request made by the Administrator under section 7414 of this title and may be enforced by the Chairperson of the Board or by the Administrator as provided in such section.

(P) The Administrator shall provide to the Board such support and facilities as may be necessary for operation of the Board.

(Q) Consistent with subsection[8] (G) and section 7414(c) of this title any records, reports or information obtained by the Board shall be available to the Administrator, the Secretary of Labor, the Congress and the public, except that upon a showing satisfactory to the Board by any person that records, reports, or information, or particular part thereof (other than release or emissions data) to which the Board has access, if made public, is likely to cause substantial harm to the person's competitive position, the Board shall consider such record, report, or information or particular portion thereof confidential in accordance with section 1905 of title 18, except that such record, report, or information may be disclosed to other officers, employees, and authorized representatives of the United States concerned with carrying out this chapter or when relevant under any proceeding under this chapter. This subparagraph does not constitute authority to withhold records, reports, or information from the Congress.

(R) Whenever the Board submits or transmits any budget estimate, budget request, supplemental budget request, or other budget information, legislative recommendation, prepared testimony for congressional hearings, recommendation or study to the President, the Secretary of Labor, the Administrator, or the Director of the Office of Management and Budget, it shall concurrently transmit a copy thereof to the Congress. No report of the Board shall be subject to review by the Administrator or any Federal agency or to judicial review in any court. No officer or agency of the United States shall have authority to require the Board to submit its budget requests or estimates, legislative recommendations, prepared testimony, comments, recommendations or reports to any officer or agency of the United States for approval or review prior to the submission of such recommendations, testimony, comments or reports to the Congress. In the performance of their functions as established by this chapter, the members, officers and employees of the Board shall not be responsible to or subject to supervision or direction, in carrying out any duties under this subsection, of any officer or employee or agent of the Environmental Protection Agency, the Department of Labor or any other agency of the United States except that the President may remove any member, officer or employee of the Board for inefficiency, neglect of duty or malfeasance in office. Nothing in this section shall affect the application of title 5 to officers or employees of the Board.

(S) The Board shall submit an annual report to the President and to the Congress which shall include, but not be limited to, information on accidental releases which have been investigated by or reported to the Board during the previous year, recommendations for legislative or administrative action which the Board has made, the actions which have been taken by the Administrator or the Secretary of Labor or the heads of other agencies to implement such recommendations, an identification of priorities for study and investigation in the succeeding year, progress in the development of risk-reduction technologies and the response to and implementation of significant research findings on chemical safety in the public and private sector.

(7) Accident prevention

(A) In order to prevent accidental releases of regulated substances, the Administrator is authorized to promulgate release prevention, detection, and correction requirements which may include monitoring, record-keeping, reporting, training, vapor recovery, secondary containment, and other design, equipment, work practice, and operational requirements. Regulations promulgated under this paragraph may make distinctions between various types, classes, and kinds of facilities, devices and systems taking into consideration factors including, but not limited to, the size, location, process, process controls, quantity of substances handled, potency of substances, and response capabilities present at any stationary source. Regulations promulgated pursuant to this subparagraph shall have an effective date, as determined by the Administrator, assuring compliance as expeditiously as practicable.

(B)(i) Within 3 years after November 15, 1990, the Administrator shall promulgate reasonable regulations and appropriate guidance to provide, to the greatest extent practicable, for the prevention and detection of accidental releases of regulated substances and for response to such releases by the owners or operators of the sources of such releases. The Administrator shall utilize the expertise of the Secretaries of Transportation and Labor in promulgating such regulations. As appropriate, such regulations shall cover the use, operation, repair, replacement, and maintenance of equipment to monitor, detect, inspect, and control such releases, including training of persons in the use and maintenance of such equipment and in the conduct of periodic inspections. The regulations shall include procedures and measures for emergency response after an accidental release of a regulated substance in order to protect human health and the envi-

[8] So in original. Probably should be "subparagraph".

ronment. The regulations shall cover storage, as well as operations. The regulations shall, as appropriate, recognize differences in size, operations, processes, class and categories of sources and the voluntary actions of such sources to prevent such releases and respond to such releases. The regulations shall be applicable to a stationary source 3 years after the date of promulgation, or 3 years after the date on which a regulated substance present at the source in more than threshold amounts is first listed under paragraph (3), whichever is later.

(ii) The regulations under this subparagraph shall require the owner or operator of stationary sources at which a regulated substance is present in more than a threshold quantity to prepare and implement a risk management plan to detect and prevent or minimize accidental releases of such substances from the stationary source, and to provide a prompt emergency response to any such releases in order to protect human health and the environment. Such plan shall provide for compliance with the requirements of this subsection and shall also include each of the following:

(I) a hazard assessment to assess the potential effects of an accidental release of any regulated substance. This assessment shall include an estimate of potential release quantities and a determination of downwind effects, including potential exposures to affected populations. Such assessment shall include a previous release history of the past 5 years, including the size, concentration, and duration of releases, and shall include an evaluation of worst case accidental releases;

(II) a program for preventing accidental releases of regulated substances, including safety precautions and maintenance, monitoring and employee training measures to be used at the source; and

(III) a response program providing for specific actions to be taken in response to an accidental release of a regulated substance so as to protect human health and the environment, including procedures for informing the public and local agencies responsible for responding to accidental releases, emergency health care, and employee training measures.

At the time regulations are promulgated under this subparagraph, the Administrator shall promulgate guidelines to assist stationary sources in the preparation of risk management plans. The guidelines shall, to the extent practicable, include model risk management plans.

(iii) The owner or operator of each stationary source covered by clause (ii) shall register a risk management plan prepared under this subparagraph with the Administrator before the effective date of regulations under clause (i) in such form and manner as the Administrator shall, by rule, require. Plans prepared pursuant to this subparagraph shall also be submitted to the Chemical Safety and Hazard Investigation Board, to the State in which the stationary source is located, and to any local agency or entity having responsibility for planning for or responding to accidental releases which may occur at such source, and shall be available to the public under section 7414(c) of this title. The Administrator shall establish, by rule, an auditing system to regularly review and, if necessary, require revision in risk management plans to assure that the plans comply with this subparagraph. Each such plan shall be updated periodically as required by the Administrator, by rule.

(C) Any regulations promulgated pursuant to this subsection shall to the maximum extent practicable, consistent with this subsection, be consistent with the recommendations and standards established by the American Society of Mechanical Engineers (ASME), the American National Standards Institute (ANSI) or the American Society of Testing Materials (ASTM). The Administrator shall take into consideration the concerns of small business in promulgating regulations under this subsection.

(D) In carrying out the authority of this paragraph, the Administrator shall consult with the Secretary of Labor and the Secretary of Transportation and shall coordinate any requirements under this paragraph with any requirements established for comparable purposes by the Occupational Safety and Health Administration or the Department of Transportation. Nothing in this subsection shall be interpreted, construed or applied to impose requirements affecting, or to grant the Administrator, the Chemical Safety and Hazard Investigation Board, or any other agency any authority to regulate (including requirements for hazard assessment), the accidental release of radionuclides arising from the construction and operation of facilities licensed by the Nuclear Regulatory Commission.

(E) After the effective date of any regulation or requirement imposed under this subsection, it shall be unlawful for any person to operate any stationary source subject to such regulation or requirement in violation of such regulation or requirement. Each regulation or requirement under this subsection shall for purposes of sections 7413, 7414, 7416, 7420, 7604, and 7607 of this title and other enforcement provisions of this chapter, be treated as a standard in effect under subsection (d).

(F) Notwithstanding the provisions of subchapter V or this section, no stationary source shall be required to apply for, or operate pursuant to, a permit issued under such subchapter solely because such source is subject to regulations or requirements under this subsection.

(G) In exercising any authority under this subsection, the Administrator shall not, for purposes of section 653(b)(1) of title 29, be deemed to be exercising statutory authority to prescribe or enforce standards or regulations affecting occupational safety and health.

(H) PUBLIC ACCESS TO OFF-SITE CONSEQUENCE ANALYSIS INFORMATION.—

(i) DEFINITIONS.—In this subparagraph:

(I) COVERED PERSON.—The term ''covered person'' means—

(aa) an officer or employee of the United States;

(bb) an officer or employee of an agent or contractor of the Federal Government;

(cc) an officer or employee of a State or local government;

(dd) an officer or employee of an agent or contractor of a State or local government;

(ee) an individual affiliated with an entity that has been given, by a State or local government, responsibility for preventing, planning for, or responding to accidental releases;

(ff) an officer or employee or an agent or contractor of an entity described in item (ee); and

(gg) a qualified researcher under clause (vii).

(II) OFFICIAL USE.—The term ''official use'' means an action of a Federal, State, or local government agency or an entity referred to in subclause (I)(ee) intended to carry out a function relevant to preventing, planning for, or responding to accidental releases.

(III) OFF-SITE CONSEQUENCE ANALYSIS INFORMATION.—The term ''off-site consequence analysis information'' means those portions of a risk management plan, excluding the executive summary of the plan, consisting of an evaluation of 1 or more worst-case release scenarios or alternative release scenarios, and any electronic data base created by the Administrator from those portions.

(IV) RISK MANAGEMENT PLAN.—The term ''risk management plan'' means a risk management plan submitted to the Administrator by an owner or operator of a stationary source under subparagraph (B)(iii).

(ii) REGULATIONS.—Not later than 1 year after August 5, 1999, the President shall—

(I) assess—

(aa) the increased risk of terrorist and other criminal activity associated with the posting of off-site consequence analysis information on the Internet; and

(bb) the incentives created by public disclosure of off-site consequence analysis information for reduction in the risk of accidental releases; and

(II) based on the assessment under subclause (I), promulgate regulations governing the distribution of off-site consequence analysis information in a manner that, in the opinion of the President, minimizes the likelihood of accidental releases and the risk described in subclause (I)(aa) and the likelihood of harm to public health and welfare, and—

(aa) allows access by any member of the public to paper copies of off-site consequence analysis information for a limited number of stationary sources located anywhere in the United States, without any geographical restriction;

(bb) allows other public access to off-site consequence analysis information as appropriate;

(cc) allows access for official use by a covered person described in any of items (cc) through (ff) of clause (i)(I) (referred to in this subclause as a ''State or local covered person'') to off-site consequence analysis information relating to stationary sources located in the person's State;

(dd) allows a State or local covered person to provide, for official use, off-site consequence analysis information relating to stationary sources located in the person's State to a State or local covered person in a contiguous State; and

(ee) allows a State or local covered person to obtain for official use, by request to the Administrator, off-site consequence analysis information that is not available to the person under item (cc).

(iii) AVAILABILITY UNDER FREEDOM OF INFORMATION ACT.—

(I) FIRST YEAR.—Off-site consequence analysis information, and any ranking of stationary sources derived from the information, shall not be made available under section 552 of title 5 during the 1-year period beginning on August 5, 1999.

(II) AFTER FIRST YEAR.—If the regulations under clause (ii) are promulgated on or before the end of the period described in subclause (I), off-site consequence analysis information covered by the regulations, and any ranking of stationary sources derived from the information, shall not be made available under section 552 of title 5 after the end of that period.

(III) APPLICABILITY.—Subclauses (I) and (II) apply to off-site consequence analysis information submitted to the Administrator before, on, or after August 5, 1999.

(iv) AVAILABILITY OF INFORMATION DURING TRANSITION PERIOD.—The Administrator shall make off-site consequence analysis information available to covered persons for official use in a manner that meets the requirements of items (cc) through (ee) of clause (ii)(II), and to the public in a form that does not make available any information concerning the identity or location of stationary sources, during the period—

(I) beginning on August 5, 1999; and

(II) ending on the earlier of the date of promulgation of the regulations under clause (ii) or the date that is 1 year after August 5, 1999.

(v) PROHIBITION ON UNAUTHORIZED DISCLOSURE OF INFORMATION BY COVERED PERSONS.—

(I) IN GENERAL.—Beginning on August 5, 1999, a covered person shall not disclose to the public off-site consequence analysis information in any form, or any statewide or national ranking of identified stationary sources derived from such information, except as authorized by this subparagraph (including the regulations promulgated under clause (ii)). After the end of the 1-year period beginning on August 5, 1999, if regulations have not been promulgated under clause (ii), the preceding sentence shall not apply.

(II) CRIMINAL PENALTIES.—Notwithstanding section 7413 of this title, a covered person that willfully violates a restriction or prohibition established by this subparagraph (including the regulations promulgated under clause (ii)) shall, upon conviction, be fined for an infraction under section 3571 of title 18 (but shall not be subject to imprisonment) for each unauthorized disclosure of off-site consequence analysis information, except that subsection (d) of such section 3571 shall not apply to a case in which the offense results in pecuniary loss unless the defendant knew that such loss would occur. The disclosure of off-site consequence analysis information for each specific stationary source shall be considered a separate offense. The total of all penalties that may be imposed on a single person or organization under this item shall not exceed $1,000,000 for violations committed during any 1 calendar year.

(III) APPLICABILITY.—If the owner or operator of a stationary source makes off-site consequence analysis information relating to that stationary source available to the public without restriction—

(aa) subclauses (I) and (II) shall not apply with respect to the information; and

(bb) the owner or operator shall notify the Administrator of the public availability of the information.

(IV) LIST.—The Administrator shall maintain and make publicly available a list of all stationary sources that have provided notification under subclause (III)(bb).

(vi) NOTICE.—The Administrator shall provide notice of the definition of official use as provided in clause (i)(III)[9] and examples of actions that would and would not meet that definition, and notice of the restrictions on further dissemination and the penalties established by this chapter to each covered person who receives off-site consequence analysis information under clause (iv) and each covered person who receives off-site consequence analysis information for an official use under the regulations promulgated under clause (ii).

(vii) QUALIFIED RESEARCHERS.—

(I) IN GENERAL.—Not later than 180 days after August 5, 1999, the Administrator, in consultation with the Attorney General, shall develop and implement a system for providing off-site consequence analysis information, including facility identification, to any qualified researcher, including a qualified researcher from industry or any public interest group.

(II) LIMITATION ON DISSEMINATION.—The system shall not allow the researcher to disseminate, or make available on the Internet, the off-site consequence analysis information, or any portion of the off-site consequence analysis information, received under this clause.

(viii) READ-ONLY INFORMATION TECHNOLOGY SYSTEM.—In consultation with the Attorney General and the heads of other appropriate Federal agencies, the Administrator shall establish an information technology system that provides for the availability to the public of off-site consequence analysis information by means of a central data base under the control of the Federal Government that contains information that users may read, but that provides no means by which an electronic or mechanical copy of the information may be made.

(ix) VOLUNTARY INDUSTRY ACCIDENT PREVENTION STANDARDS.—The Environmental Protection Agency, the Department of Justice, and other appropriate agencies may provide technical assistance to owners and operators of stationary sources and participate in the development of voluntary industry standards that will help achieve the objectives set forth in paragraph (1).

(x) EFFECT ON STATE OR LOCAL LAW.—

(I) IN GENERAL.—Subject to subclause (II), this subparagraph (including the regulations promulgated under this subparagraph) shall supersede any provision of State or local law that is inconsistent with this subparagraph (including the regulations).

(II) AVAILABILITY OF INFORMATION UNDER STATE LAW.—Nothing in this subparagraph precludes a State from making available data on the off-site consequences of chemical releases collected in accordance with State law.

(xi) REPORT.—

(I) IN GENERAL.—Not later than 3 years after August 5, 1999, the Attorney General, in consultation with appropriate State, local, and Federal Government agencies, affected industry, and the public, shall submit to Congress a report that describes the extent to which regulations promulgated under this paragraph have resulted in actions, including the design and maintenance of safe facilities, that are effective in detecting, preventing, and minimizing the consequences of releases of regulated substances that may be caused by criminal activity. As part of this report, the Attorney General, using available data to the extent possible, and a sampling of covered stationary sources selected at the discretion of the Attorney General, and in consultation with appropriate State, local, and Federal governmental agencies, affected industry, and the public, shall review the vulnerability of covered stationary sources to criminal and terrorist activity, current industry practices regarding site security, and security of transportation of regulated substances. The Attorney General shall submit this report, containing the results of the review, together with recommendations, if any, for reducing vulnerability of covered sta-

[9] So in original. Probably should be "(i)(II)".

tionary sources to criminal and terrorist activity, to the Committee on Commerce of the United States House of Representatives and the Committee on Environment and Public Works of the United States Senate and other relevant committees of Congress.

(II) INTERIM REPORT.—Not later than 12 months after August 5, 1999, the Attorney General shall submit to the Committee on Commerce of the United States House of Representatives and the Committee on Environment and Public Works of the United States Senate, and other relevant committees of Congress, an interim report that includes, at a minimum—

(aa) the preliminary findings under subclause (I);

(bb) the methods used to develop the findings; and

(cc) an explanation of the activities expected to occur that could cause the findings of the report under subclause (I) to be different than the preliminary findings.

(III) AVAILABILITY OF INFORMATION.—Information that is developed by the Attorney General or requested by the Attorney General and received from a covered stationary source for the purpose of conducting the review under subclauses (I) and (II) shall be exempt from disclosure under section 552 of title 5 if such information would pose a threat to national security.

(xii) SCOPE.—This subparagraph—

(I) applies only to covered persons; and

(II) does not restrict the dissemination of off-site consequence analysis information by any covered person in any manner or form except in the form of a risk management plan or an electronic data base created by the Administrator from off-site consequence analysis information.

(xiii) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Administrator and the Attorney General such sums as are necessary to carry out this subparagraph (including the regulations promulgated under clause (ii)), to remain available until expended.

(8) Research on hazard assessments

The Administrator may collect and publish information on accident scenarios and consequences covering a range of possible events for substances listed under paragraph (3). The Administrator shall establish a program of long-term research to develop and disseminate information on methods and techniques for hazard assessment which may be useful in improving and validating the procedures employed in the preparation of hazard assessments under this subsection.

(9) Order authority

(A) In addition to any other action taken, when the Administrator determines that there may be an imminent and substantial endangerment to the human health or welfare or the environment because of an actual or threatened accidental release of a regulated substance, the Administrator may secure such relief as may be necessary to abate such danger or threat, and the district court of the United States in the district in which the threat occurs shall have jurisdiction to grant such relief as the public interest and the equities of the case may require. The Administrator may also, after notice to the State in which the stationary source is located, take other action under this paragraph including, but not limited to, issuing such orders as may be necessary to protect human health. The Administrator shall take action under section 7603 of this title rather than this paragraph whenever the authority of such section is adequate to protect human health and the environment.

(B) Orders issued pursuant to this paragraph may be enforced in an action brought in the appropriate United States district court as if the order were issued under section 7603 of this title.

(C) Within 180 days after November 15, 1990, the Administrator shall publish guidance for using the order authorities established by this paragraph. Such guidance shall provide for the coordinated use of the authorities of this paragraph with other emergency powers authorized by section 9606 of this title, sections 311(c), 308, 309 and 504(a) of the Federal Water Pollution Control Act [33 U.S.C. 1321(c), 1318, 1319, 1364(a)], sections 3007, 3008, 3013, and 7003 of the Solid Waste Disposal Act [42 U.S.C. 6927, 6928, 6934, 6973], sections 1445 and 1431 of the Safe Drinking Water Act [42 U.S.C. 300j–4, 300i], sections 5 and 7 of the Toxic Substances Control Act [15 U.S.C. 2604, 2606], and sections 7413, 7414, and 7603 of this title.

(10) Presidential review

The President shall conduct a review of release prevention, mitigation and response authorities of the various Federal agencies and shall clarify and coordinate agency responsibilities to assure the most effective and efficient implementation of such authorities and to identify any deficiencies in authority or resources which may exist. The President may utilize the resources and solicit the recommendations of the Chemical Safety and Hazard Investigation Board in conducting such review. At the conclusion of such review, but not later than 24 months after November 15, 1990, the President shall transmit a message to the Congress on the release prevention, mitigation and response activities of the Federal Government making such recommendations for change in law as the President may deem appropriate. Nothing in this paragraph shall be interpreted, construed or applied to authorize the President to modify or reassign release prevention, mitigation or response authorities otherwise established by law.

(11) State authority

Nothing in this subsection shall preclude, deny or limit any right of a State or political subdivision thereof to adopt or enforce any regulation, requirement, limitation or standard (including any procedural requirement) that is more stringent than a regulation, requirement, limitation or standard in effect under this subsection or that applies to a substance not subject to this subsection.

(s) Periodic report

Not later than January 15, 1993 and every 3 years thereafter, the Administrator shall prepare and transmit to the Congress a comprehensive report on the measures taken by the Agency and by the States to implement the provisions of this section. The Administrator shall maintain a database on pollutants and sources subject to the provisions of this section and shall include aggregate information from the database in each annual report. The report shall include, but not be limited to—

(1) a status report on standard-setting under subsections (d) and (f);

(2) information with respect to compliance with such standards including the costs of compliance experienced by sources in various categories and subcategories;

(3) development and implementation of the national urban air toxics program; and

(4) recommendations of the Chemical Safety and Hazard Investigation Board with respect to the prevention and mitigation of accidental releases.

(July 14, 1955, ch. 360, title I, §112, as added Pub. L. 91–604, §4(a), Dec. 31, 1970, 84 Stat. 1685; amended Pub. L. 95–95, title I, §§109(d)(2), 110, title IV, §401(c), Aug. 7, 1977, 91 Stat. 701, 703, 791; Pub. L. 95–623, §13(b), Nov. 9, 1978, 92 Stat. 3458; Pub. L. 101–549, title III, §301, Nov. 15, 1990, 104 Stat. 2531; Pub. L. 102–187, Dec. 4, 1991, 105 Stat. 1285; Pub. L. 105–362, title IV, §402(b), Nov. 10, 1998, 112 Stat. 3283; Pub. L. 106–40, §§2, 3(a), Aug. 5, 1999, 113 Stat. 207, 208.)

Editorial Notes

References in Text

The date of enactment, referred to in subsec. (a)(11), probably means the date of enactment of Pub. L. 101–549, which amended this section generally and was approved Nov. 15, 1990.

The Atomic Energy Act, referred to in subsec. (d)(9), probably means the Atomic Energy Act of 1954, act Aug. 1, 1946, ch. 724, as added by act Aug. 30, 1954, ch. 1073, §1, 68 Stat. 919, which is classified principally to chapter 23 (§2011 et seq.) of this title. For complete classification of this Act to the Code, see Short Title note set out under section 2011 of this title and Tables.

The Federal Water Pollution Control Act, referred to in subsecs. (e)(5) and (m)(1)(D), (5)(D), is act June 30, 1948, ch. 758, as amended generally by Pub. L. 92–500, §2, Oct. 18, 1972, 86 Stat. 816, which is classified generally to chapter 26 (§1251 et seq.) of Title 33, Navigation and Navigable Waters. Title II of the Act is classified generally to subchapter II (§1281 et seq.) of chapter 26 of Title 33. For complete classification of this Act to the Code, see Short Title note set out under section 1251 of Title 33 and Tables.

The Toxic Substances Control Act, referred to in subsec. (k)(3)(C), is Pub. L. 94–469, Oct. 11, 1976, 90 Stat. 2003, which is classified generally to chapter 53 (§2601 et seq.) of Title 15, Commerce and Trade. For complete classification of this Act to the Code, see Short Title note set out under section 2601 of Title 15 and Tables.

The Federal Insecticide, Fungicide and Rodenticide Act, referred to in subsec. (k)(3)(C), probably means the Federal Insecticide, Fungicide, and Rodenticide Act, act June 25, 1947, ch. 125, as amended generally by Pub. L. 92–516, Oct. 21, 1972, 86 Stat. 973, which is classified generally to subchapter II (§136 et seq.) of chapter 6 of Title 7, Agriculture. For complete classification of this Act to the Code, see Short Title note set out under section 136 of Title 7 and Tables.

The Resource Conservation and Recovery Act, referred to in subsec. (k)(3)(C), probably means the Resource Conservation and Recovery Act of 1976, Pub. L. 94–580, Oct. 21, 1976, 90 Stat. 2796, as amended, which is classified generally to chapter 82 (§6901 et seq.) of this title. For complete classification of this Act to the Code, see Short Title of 1976 Amendment note set out under section 6901 of this title and Tables.

The Safe Drinking Water Act, referred to in subsec. (m)(1)(D), (5)(D), is title XIV of act July 1, 1944, as added Dec. 16, 1974, Pub. L. 93–523, §2(a), 88 Stat. 1660, which is classified generally to subchapter XII (§300f et seq.) of chapter 6A of this title. For complete classification of this Act to the Code, see Short Title note set out under section 201 of this title and Tables.

The Solid Waste Disposal Act, referred to in subsec. (n)(7), is title II of Pub. L. 89–272, Oct. 20, 1965, 79 Stat. 997, as amended generally by Pub. L. 94–580, §2, Oct. 21, 1976, 90 Stat. 2795. Subtitle C of the Act is classified generally to subchapter III (§6921 et seq.) of chapter 82 of this title. For complete classification of this Act to the Code, see Short Title note set out under section 6901 of this title and Tables.

Section 303 of the Clean Air Act Amendments of 1990, referred to in subsec. (*o*)(4), probably means section 303 of Pub. L. 101–549, which is set out below.

The Clean Air Act Amendments of 1990, referred to in subsec. (q)(1)–(3), probably means Pub. L. 101–549, Nov. 15, 1990, 104 Stat. 2399. For complete classification of this Act to the Code, see Short Title note set out under section 7401 of this title and Tables.

The Emergency Planning and Community Right-To-Know Act of 1986, referred to in subsec. (r)(3), is title III of Pub. L. 99–499, Oct. 17, 1986, 100 Stat. 1728, which is classified generally to chapter 116 (§11001 et seq.) of this title. For complete classification of this Act to the Code, see Short Title note set out under section 11001 of this title and Tables.

The Occupational Safety and Health Act, referred to in subsec. (r)(6)(C)(ii), (K), (L), probably means the Occupational Safety and Health Act of 1970, Pub. L. 91–596, Dec. 29, 1970, 84 Stat. 1590, as amended, which is classified principally to chapter 15 (§651 et seq.) of Title 29, Labor. For complete classification of this Act to the Code, see Short Title note set out under section 651 of Title 29 and Tables.

Codification

In subsec. (r)(6)(N), ''section 6101 of title 41'' substituted for ''section 5 of title 41 of the United States Code'' on authority of Pub. L. 111–350, §6(c), Jan. 4, 2011, 124 Stat. 3854, which Act enacted Title 41, Public Contracts.

Section was formerly classified to section 1857c–7 of this title.

Amendments

1999—Subsec. (r)(2)(D). Pub. L. 106–40, §2(5), added subpar. (D).

Subsec. (r)(4). Pub. L. 106–40, §2, substituted ''Administrator—

''(A) shall consider—''

for ''Administrator shall consider each of the following criteria—'' in introductory provisions, redesignated subpars. (A) to (C) as cls. (i) to (iii), respectively, of subpar. (A) and added subpar. (B).

Subsec. (r)(7)(H). Pub. L. 106–40, §3(a), added subpar. (H).

1998—Subsec. (n)(2)(C). Pub. L. 105–362 substituted ''On completion of the study, the Secretary shall submit to Congress a report on the results of the study and'' for ''The Secretary shall prepare annual reports to Congress on the status of the research program and at the completion of the study''.

APPENDIX C

SELECT RULEMAKING DOCUMENTS FOR THE FINAL RULE

TALEN MONTANA

COMMENTS OF TALEN MONTANA, LLC ON THE PROPOSAL ON NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW

Docket ID: EPA-HQ-OAR-2018-0794

I. INTRODUCTION

On April 24, 2023, EPA published in the *Federal Register*, at 88 Fed. Reg. 24,854, a Proposal that would amend the National Emission Standards for Hazardous Air Pollutants ("NESHAP") for coal- and oil-fired electric utility steam generating units ("EGUs") — *i.e.*, the Mercury and Air Toxics Standards ("MATS") ("Proposal" or "Proposed Rule"). Among other amendments, EPA is proposing to: (i) tighten the surrogate filterable particulate matter ("fPM") standard for demonstrating compliance with the emissions limits for non-mercury ("non-Hg") metal hazardous air pollutants ("HAPs") from 0.03 lb/MMBtu to 0.010 lb/MMBtu; and (ii) require continuous emissions monitoring systems ("CEMS") for demonstrating compliance with the fPM standard.[1]

Talen Montana, LLC ("Talen Montana") is part-owner and operator of Units 3&4 of the Colstrip Steam Electric Station ("Colstrip") in Rosebud County, Montana. On behalf of itself as an owner and with knowledge gained as the operator of Colstrip, Talen Montana has significant concerns about the Proposed Rule, particularly with the proposed tightening of the fPM standard. These concerns stem from the unique design and circumstances of Colstrip. Colstrip currently uses venturi wet scrubbers to address both sulfur dioxide ("SO_2") and fPM emissions. It would be extremely expensive — and potentially cost prohibitive — for Colstrip to comply with the 0.010 lb/MMBtu fPM limit because the venturi wet scrubbers cannot meet that limit. Colstrip would need to undertake a massive and complex construction project to install new controls — either new fabric filters ("FFs") or electrostatic precipitators ("ESPs") — when Colstrip's remaining life and future generation is likely limited given EPA's other rulemakings targeting older sources like Colstrip. The high costs associated with installing, testing, and implementing new controls, coupled with limited time and electric generation for the recovery of such costs, may cause Colstrip to shut down prematurely if the owners deem that it is not economically feasible to install the necessary controls to comply with the proposed fPM standard.

A premature shutdown of Colstrip would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission, factors that were not considered by EPA in setting the proposed fPM standard. Moreover, Colstrip bears a hugely disproportionate burden under the Proposed Rule, especially where EPA has not found any unacceptable risk related to Colstrip's (or any other affected facility's) operation under the current fPM standard. Indeed, by EPA's own calculations, Colstrip is expected to bear almost 50 percent

[1] *See* 88 Fed. Reg. 24,854 (Apr. 24, 2023).

of the costs of the Proposed Rule. For these reasons, as well as other legal and technical reasons discussed below, Talen Montana asks that EPA not finalize the proposed 0.010 lb/MMBtu fPM limit. However, should EPA ultimately finalize the proposed 0.010 lb/MMBtu fPM limit, Talen strongly urges EPA to establish a subcategory for coal-fired units that use wet scrubbers to address both SO_2 and PM emissions and that do not presently have an ESP or FF, where the fPM limit for those units is no lower than 0.025 lb/MMBtu fPM. Given that EPA's rationale for the Proposed Rule is that existing control technology is more effective and cost effective than was known at the time of the original MATS rule, a targeted limit that is specific to the existing wet scrubber technology is consistent and appropriate with that approach.

As an additional alternative, Talen Montana requests that EPA establish a subcategory for near-term existing coal units electing to retire where the fPM limit remains at 0.030 lb/MMBtu until ceasing operations. This would be consistent with the approach EPA has taken in other rulemakings. Under such an approach, units could opt-in to the subcategory by making an enforceable retirement commitment within a specified timeline after the Proposed Rule is finalized and with retirement planned by a specified date. For this subcategory, Talen Montana proposes that units opt-in within 18 months after the effective date of the final rule with a retirement date no later than December 31, 2035 (with a "safety valve" that would allow longer operation depending on circumstances in the future, as described below).

II. BACKGROUND

Colstrip is one of the largest coal-fired electric generating facilities west of the Mississippi River, supplying electricity throughout Montana and the Pacific Northwest. Talen Montana has a 15% ownership stake in Colstrip, which currently consists of two active coal-fired generating units capable of producing up to 1,480 MW of electricity that have been operating for approximately 37 years. Each of the units has approximately 740 MW of generating capacity, and the adjacent Rosebud coal mine supplies Colstrip's low-sulfur subbituminous coal.

A. Colstrip's Unique Design

Colstrip's design sets it apart from other coal-fired units in the country that are currently operating. Colstrip began construction in the 1970s and Units 3 and 4 began operations in the 1980s. Colstrip was designed to utilize low-sulfur coal and with then state-of-the-art venturi wet scrubbers to reduce its SO_2 emissions below the applicable limits. Colstrip also relies on the venturi wet scrubbers to mitigate fPM.

Colstrip has eight wet venturi scrubbers on each of unit. Seven scrubbers are used during normal full load operation and one scrubber is a "backup," used only when one of the other seven scrubbers in operation needs to be removed from service or is undergoing routine cleaning and maintenance. Below is a diagram of the wet venturi scrubber used at Colstrip Units 3&4:

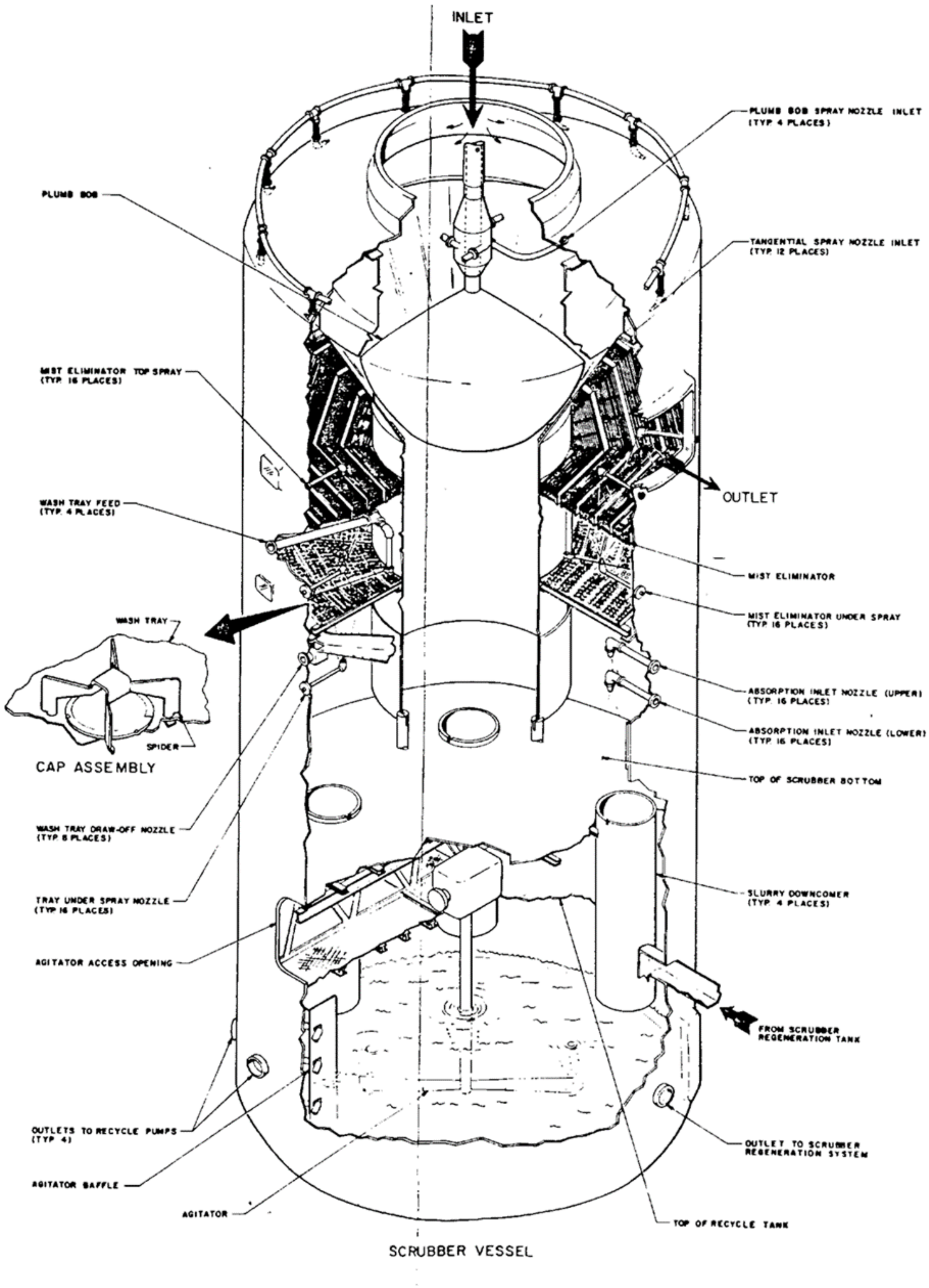


Figure 1 - Diagram of Colstrip Scrubber

The venturi wet scrubbers at Colstrip Units 3 and 4 remove approximately 99.7% of fly ash particulate from the flue gas and 95% of the SO2 via a sequence of removal processes. The flue gas enters the scrubber vessel and is accelerated by the converging surfaces of the plumb bob and venturi bowl. The flue gas and slurry meet in the venturi throat where turbulence atomizes the slurry. Acceleration of the flue gas causes the particulate to collide with and be absorbed by slurry droplets. The majority of the fly ash particulate and most of the SO_2 are removed in the venturi section. The wet venturi scrubbers utilize the alkalinity of the fly ash particle removed to help meet the high level of SO_2 removal. The throat area of the venturi is adjusted by moving the plumb bob up or down to obtain the desired pressure drop across the plumb bob of each scrubber. The flue gas velocity caused by this pressure drop ensures optimum fly ash removal. The slurry and collected fly ash are separated from the flue gas as it turns up to enter the absorption area. The flue gas then enters the absorption spray area in the annular space between the downcomer and shell of the scrubber vessel. The flue gas is contacted with recycle slurry for additional removal of SO_2. Above the absorption section is the wash tray which uses recirculation water to contact the flue gas and remove entrained recycle slurry from the flue gas. The flue gas then flows through the mist eliminator where entrained droplets are removed.

As EPA recognized, Colstrip does not have a FF or an ESP and would need to install one to comply with the proposed 0.010 lb/MMBtu fPM limit, as the current venturi wet scrubbers will not be able to meet the proposed limit.[2] While EPA recognizes that Colstrip's venturi wet scrubbers would not be able to comply with the proposed limit, EPA assumes Colstrip could make a "minimal cost ($10/kW) for [wet scrubber] maintenance or minor upgrades . . . to meet a potential 0.015 lb/MMBtu standard."[3] This assumption, however, is inaccurate. Colstrip has typically been able to remain just below the current limit of 0.030 lb/MMBtu. However, due to occasional variability in fuel and operating condition, Colstrip has, since 2018, hired consultants and engineers to explore ways to further enhance the efficiencies of the venturi wet scrubbers. This work, as described below, has made the venturi wet scrubber emissions more stable. But, as reflected in Attachment A (Colstrip's MATS PM CEMS compliance data from September 2018 to April 2023), the work demonstrated that 0.015 lb/MMBtu fPM is not achievable with upgrades to the existing wet scrubbers and further that the efforts to reduce fPM emissions with the existing control technology has reached its limits:

- The original operating condition for the plumb bob delta P (pressure drop) was 17" to meet particulate and SO2 removal requirements. In an effort to optimize the performance of the scrubbers, the plumb bob delta P is currently operated at 27-28", the maximum delta P achievable which is limited by the capability of the induced draft ("ID") Fans.

- The original mist eliminators have been upgraded with improved performance to better control entrained droplets in the flue gas. In 2018, the mist eliminator supplier (Munters)

---

[2] *See* 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category ("Technical Memo"), Doc. ID. EPA-HQ-OAR-2018-0794-5789, at PDF p. 9, posted Apr. 24, 2023.
[3] *See id.*

conducted a mist eliminator performance test, and the results showed dry conditions with very little or any droplet carry over.

- Scrubber slurry solids level has been controlled to 25-30% solids to minimize potential particulate contribution from entrained droplets in the flue gas.
- Flow distribution plates have been installed on each scrubber to improve the flow balance across the scrubber, provide a more uniform flow, and improve particulate removal performance.

Colstrip also implemented additional measures to address combustion conditions to help ensure that combustion of the coal occurs in a manner that prevents to formation of small fly ash particles that are difficult to remove in the wet venturi scrubbers, including:

- Combustion tuning and incorporation of optimum conditions over variable operating conditions into the Combustion Optimizer System.
- Optimization of the furnace sootblower system to ensure optimum heat transfer in the furnace and prevent elevated temperatures in the upper part of the furnace that can contribute to formation of small particulate particles that are difficult to remove in the wet venturi scrubbers.
- Optimization of coal mill fineness by regularly performing coal mill sieve analysis to ensure correct particle size distribution of the coal entering the furnace.

Together, these comprehensive efforts reflect all known upgrades available to be implemented to the Colstrip scrubber/combustion process to reduce fPM, which enables Colstrip to achieve compliance with the current 0.030 lb/MMBtu fPM limit with an adequate compliance margin. While the majority of stack testing has shown emission rates between 0.020 lb/MMBtu and 0.025 lb/MMBtu fPM, there have been several instances where stack tests were above 0.025 lb/MMBtu fPM.[4] In 2022, based on stack tests, the two units combined achieved approximately 0.022 lb/MMBtu fPM on an annual basis.

With the extensive scrubber/combustion process reviews by consultants and engineers and implementation of the upgrades previously identified, Talen Montana believes that these efforts have optimized the current control technology to the maximum extent feasible. While Colstrip remains dedicated to continued optimization to control fPM, Colstrip cannot meet a the more stringent fPM limits in the Proposed Rule (either the 0.015 lb/MMBtu or the proposed 0.010 lb/MMBtu) without installation of a FF or ESP, which as noted previously would be a massive, complex, and expensive construction project.

[4] *See* Attachment A.

B. Colstrip's Unique Circumstances

Despite the importance of Colstrip to Montana and the surrounding region, Colstrip's future is uncertain. Colstrip's remaining life and future generation may be limited by the Inflation Reduction Act ("IRA"), which EPA's IPM runs suggest will cause Colstrip to significantly reduce generation as more renewables come online and other EPA rulemakings targeting older sources such as Colstrip are implemented. These rulemakings, excluding forthcoming ones, impacting Colstrip include: (i) the proposed rule on the Hazardous Solid Waste Management System: Disposal of Coal Combustion Residuals ("CCR") from Electric Utilities; Legacy CCR Surface Impoundments (88 Fed. Reg. 31,982 (May 18, 2023)) ("Proposed CCR Rule"); and (ii) the proposed rule on New Source Performance Standards for Greenhouse Gas ("GHG") Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired EGUs; and Repeal of the Affordable Clean Energy Rule (88 Fed. Reg. 33,240 (May 23, 2023)) ("Proposed GHG Rule").

The costs associated with complying with the proposed fPM limit, compounded with the proposed requirements in these other rulemakings, are massive. Given the reduced lifespan and generation that may be on the horizon for Colstrip, it will be extremely difficult to justify installing new controls to meet such the fPM limit in the Proposed Rule. At a certain point, it is likely that the owners will determine that it is no longer economically feasible to continue operating Colstrip, as they will not be able to recoup the cost of installing controls.

Furthermore, any closure plans necessitate intensive engagement and coordination among stakeholders because Colstrip is vital to Montana and the surrounding region. As concluded in a 2017 study by University of Montana's Bureau of Business and Economic Research, "[t]he early retirement of Colstrip Units 3 and 4 would ultimately produce:

- [A]n economy with, on average, almost 3,300 fewer jobs than would have been present if the units continued to operate through the 2028-43 period[.]

- [A] loss of income received by Montana households varying between $250 and $350 million per year, adding up to a total of about $5.2 billion over the full 16-year period 2028-43. Losses in after-tax income . . . for Montana households would total almost $4.6 billion over the same period.

- [D]eclines in annual gross sales by businesses and other organization, or economic output, between $700 and $800 million, cumulating to $12.5 billion over the full sixteen period.

- [A] decline in population which occurs as works and families migrate to other economic opportunities, growing to more than 7,000 people by year 2043."[5]

Colstrip also is vital to ensuring that Montanans have affordable and reliability electricity, especially during peak winter and summer months. Colstrip is one of Montana's most important energy assets, especially as demand for reliable baseload power in the western U.S. continues to grow. As Montana state Governor Gianforte has recognized, Montana needs Colstrip.[6]

Thus, EPA's proposal to make the fPM limit more stringent, as well as require CEMS to demonstrate compliance with that limit, has far-reaching ramifications given Colstrip's unique design and circumstances. Talen Montana strongly recommends that EPA reconsider its proposed amendments or to provide the relief requested by Talen Montana herein.

III. COMMENTS

Talen Montana understands that EPA conducted the MATS Residual Risk and Technology Review ("RTR") pursuant to President Biden's Executive Order 13990.[7] The order required EPA to review certain actions undertaken by the prior administration, including the MATS RTR finalized in May 2020.[8] The 2020 MATS RTR indicated that HAP emissions from the source category are acceptable and also did not identify any cost-effective controls that would achieve further HAP emission reductions.[9] While EPA acknowledges in the Proposal that the 2020 Residual Risk Review was sound and is not proposing to modify it, EPA is proposing to determine that the 2020 Technology Review was flawed because it "did not consider developments in the cost and effectiveness of . . . proven technologies, nor did EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs."[10] Following the consideration of such factors, EPA is proposing that the updated technology review requires certain changes to MATS.[11] These changes include the fPM limit and the use of PM CEMS.[12]

[5] Barkey, Patrick M. "The Economic Impact of the Early Retirement of Colstrip Units 3 and 4 Final Report," June 2018 at 6.
[6] "Governor Gianforte: 'Montana Needs Colstrip,'" State of Montana Newsroom, Jan. 17, 2023, https://news.mt.gov/Governors-Office/Governor_Gianforte_Montana_Needs_Colstrip.
[7] 88 Fed. Reg. at 24,856.
[8] *See* National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units-Reconsideration of Supplemental Finding and Residual Risk and Technology Review, 85 Fed. Reg. 31,286 (May 22, 2020).
[9] *See id*.
[10] 88 Fed. Reg. at 24,865.
[11] *See id.* at 24,856.
[12] *See id.* at 24,857-58.

A. EPA Has Not Established a Sufficient Basis for Tightening the fPM Limit.

Existing coal-fired EGUs currently can demonstrate compliance with the emission limits for non-Hg metal HAPs by meeting: (i) the individual emission limits for each of the 10 non-Hg metals; (ii) an emission standard for total non-Hg metals; or (iii) a surrogate fPM emission standard of 0.030 lb/MMBtu.[13] EPA is proposing to eliminate the non-Hg HAP metals standards, leaving only the surrogate fPM standard. Further, EPA is proposing to tighten the surrogate fPM standard to 0.010 lb/MMBtu, which is comparable to the MATS new source standard of 0.09 lb/MWh fPM (equivalent to a new coal-fired EGU with a heat rate of 9.0 MMBtu/MWh).[14] EPA also is soliciting comment on whether to revise the fPM standard to an even more stringent level of 0.006 lbs/MMBtu.[15]

EPA's proposal to tighten the fPM limit is based on its evaluation that "most-existing coal-fired EGUs are reporting fPM well below the current fPM emission limit of 3.0E-02 lb/MMBtu" and that "the fleet is achieving these performance levels at lower costs than assumed during promulgation of the original MATS fPM emission limit."[16] EPA acknowledged that it did not identify any new practices, processes, or control technologies for non-Hg metal HAPs.[17] For the reasons discussed below, this rationale is not a sufficient basis for tightening the fPM limit.

1. EPA exceeds its statutory authority in 42 U.S.C. § 7412(d)(6).

42 U.S.C. § 7412(d)(6) requires EPA to "review, and revise as necessary (taking into account *developments* in practices, processes, and control technologies) emission standards . . . every eight years."[18] Among other considerations, EPA deems "[a]ny *improvements* in add-on control technology or other equipment (that were identified and considered during development of the original MACT [Maximum Achievable Control Technology] standards) that could result in additional emission reductions" as such "development" under § 7412(d).[19] But EPA has identified no such "developments" or "improvements." Rather, EPA is revising the fPM limit because the Agency says it now has more information about the cost and performance of existing technology than it did when promulgating the original MATS rule.[20] According to EPA's evaluation of such information, existing controls are cheaper and perform better than anticipated, and as discussed below, EPA's evaluation is flawed.[21]

---

[13] *See* Table 1, Emission Limits for New or Reconstructed EGUs, Subpart UUUUU, 40 C.F.R. Part 63.
[14] 88 Fed. Reg. at 24,856.
[15] *Id.* at 24,857.
[16] *Id.* at 24,868.
[17] *Id.* at 24,867-68.
[18] 42 U.S.C. § 7412(d)(6) (emphasis added).
[19] 88 Fed. Reg. at 24,863.
[20] *See id.* at 24,863 fn. 15. *See also* National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304 (Feb. 16, 2012).
[21] *See* 88 Fed. Reg. at 24,867-68.

The statute places guardrails on EPA's discretion to revise the existing standards. EPA does recognize that § 7412(d)(6) provides the Agency with authority to revise emission standards but only on specific grounds. This is most evidently reflected in a mere footnote that EPA inserted in the Proposed Rule, where EPA explains that the term "developments" could encompass "getting new or better information about the performance of an add-on or existing control technology (*e.g.*, emissions data from affected sources showing an add-on control technology performs better than anticipated during development of the rule)."[22] Such an interpretation of the term "developments," however, impermissibly stretches the statutory authority EPA has in revising emission standards.[23] Nowhere does the statute provide EPA the discretion to make such revisions for any other reason not enumerated in the statute. To establish a sufficient basis for tightening the fPM limit, EPA needs to point to a *change* in practices, processes, or control technologies and equipment that justifies the corresponding change to the fPM limit. EPA has not done so. As such, EPA does not have authority to promulgate the revised fPM standards.

2. EPA's proposal to tighten the fPM limit is arbitrary and capricious.

a) EPA's evaluation of current fPM emission levels is flawed.

EPA's proposal to tighten the fPM limit is arbitrary and capricious because its evaluation justifying the proposed tightening of the fPM limit relies on questionable methods of analysis and is flawed. EPA states that its proposal to tighten the fPM standard is based on its review of "developments in the current emission levels of fPM from existing coal-fired EGUs, the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a standard that is more stringent than 3.0 E-02 lb/MMBtu and the other statutory factors."[24] According to EPA:

> Currently, 96 percent of existing coal-fired capacity without known retirement plans before the proposed compliance period already have *demonstrated* an emission rate of 1.5E-02 lb/MMBtu or lower, 91 percent of existing coal-fired capacity have *demonstrated* an emission rate of 1.0E-02 lb/MMBtu or lower, and 72 precent of existing coal-fired capacity have *demonstrated* an emission rate of 6.0E-03 lb/MMBtu or lower."[25]

The statistics above appear to be based on the evaluation summarized in the 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category ("Technical Memo"). EPA should not rely on the 96% threshold as justification for setting the proposed fPM limit at 0.010 lb/MMBtu. EPA's reliance on that evaluation is problematic for several reasons and likely overstates the universe of units that will be able to meet the proposed standard.

[22] *See* 88 Fed. Reg. 24,863 fn. 15.
[23] *See e.g.*, *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 328 (2014) ("We reaffirm the core administrative-law principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate.").
[24] *See* 88 Fed. Reg. at 24,857.
[25] *Id.* at 24,868 (emphases added).

First, the evaluation summarized in the Technical Memo excludes units that have shut down, will shut down, or will no longer burn coal/oil by December 31, 2028, or reported data in lbs/MWh.[26] By failing to include units that will shut down or no longer burn coal/oil by December 31, 2028, EPA is not appropriately accounting for units that are likely emitting fPM at levels closer to the current standard than the more stringent proposed fPM limit. EPA should have accounted for such units given that affected EGUs will have up to three years after the effective date of the final rule to demonstrate compliance with the revised limit, and some of the excluded units may not have retired or ceased burning coal or oil by the compliance deadline.[27] These units should be included when evaluating what fPM levels current technologies are capable of achieving.

If the final rule is issued before December 31, 2025, or if the announced retirements are delayed, these excluded units might become subject to a tighter standard that they cannot meet without large capital outlays to install PM control technology despite near-term projected fuel switches or retirement dates that would render such investments not cost-effective. Units that are retiring in the near-term and cannot meet the fPM limit without the installation of controls could be forced to shut down early, which could destabilize electric reliability in their service areas and could have long-lasting effects. Significant dollars would need to be spent to restart certain generating facilities if it is later determined that the decision to shut down early was detrimental to reliable grid operations. A compliance date based on three years after the final rule's effective date is inconsistent with other recent EPA rulemakings, which recognize that significant investments in emissions controls should not be required for EGUs that will retire in the near-term.

Second, the evaluation is based on selected quarterly data from 2017, 2019, and 2021.[28] The Agency fails to explain how and why it selected the specific quarterly data for those years for its evaluation when EPA has all quarterly tests and PM CEMS for the entire fleet since the effective date of the original MATS rule.[29] The Agency also fails to explain why it used a single quarter of data to present the unit's "baseline" and why "[t]he 99th percentile of the *lowest* quarter was chosen to describe the baseline fPM rate for each EGU."[30] This results in a questionable dataset comprised of an extremely small industry sample size and where a single data point is narrowed down for each EGU. For example, for Colstrip, EPA utilized a baseline of 0.018 lb/MMBtu fPM for Unit 3 and 0.021 lb/MMBtu fPM for Unit 4.[31] These numbers do not reflect what is consistently achievable for Colstrip, as Colstrip has already optimized its existing controls to the greatest extent

---

[26] *See* Technical Memo at PDF p. 2.

[27] 88 Fed. Reg. at 24,868, fn. 20. EPA excluded units that have *announced* that they will shut down by the end of 2028 based on the National Electric Energy Data System ("NEEDS") database, but such retirement plans are not legally binding and thus such units should *not* be excluded from the Agency's evaluation.

[28] Technical Memo at PDF p. 2. ("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 emissions 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).")

[29] The fact that this information had previously been extracted from CEDRI is no explanation at all. *See id.*

[30] Technical Memo at PDF p. 4. (emphasis added).

[31] *See id.* at PDF p. 4; Appendix C, *id.* at PDF p. 46.

practicable and cannot sustain emissions this low. In 2022, Colstrip achieved approximately 0.022 lb/MMBtu on an annual basis, far above EPA's assumption of the 99th percentile of the lowest quarter.

EPA should use all data available from coal-fired EGUs — except as noted below with respect to units co-firing natural gas and units with an early retirement date — to provide a full picture of achieved fPM emission rates. At the least, EPA should provide justification for its selection of the data, why reliance on the selected data is appropriate, and why certain quarterly data from 2017, 2019, and 2021 were excluded, so that interested stakeholders can verify the accuracy and representativeness of the underlying unit-specific data.[32]

Among other issues in the evaluation, EPA:

- Included some units that will be converted to gas in 2025.

- Did not include data for all quarters but instead selected only quarters with the lowest emissions for some units and excluded other quarters with higher emissions (peaking for some units, ramping for others).

- Excluded some units with no current plans to retire or switch to gas.

- Included some units that have a federally enforceable requirement to cease coal combustion by December 31, 2028 (despite stating that the evaluation excluded coal-fired EGUs that will retire by that date).

- Used the last day of a quarter in some cases and the *average* of 30-day averages for others.

- Included only certain test runs in conducting its distribution analysis.[33]

As to the last point above, EPA should use a historical data pool that encompasses data from different times of year and operating conditions. EPA should include all affected units and all operating quarters in its analysis. Without a more comprehensive data pool, it is difficult to see how EPA could conduct a proper statistical analysis to justify the proposed fPM limit. Talen Montana strongly recommends that EPA correct the deficiencies identified above, as well as make its statistical analysis or Python code used for the fPM evaluation available for public review, to ensure that the proposed fPM limit is not deemed arbitrary and capricious.

[32] It is confusing as to which units EPA included/excluded, and as to which quarterly data sets were included/excluded. EPA failed to explain its rationale for determining which units and data sets should be included or excluded. The lack of explanation, coupled with the large number of supporting documents in the docket, makes it extremely difficult to identify the unit-specific data compiled, analyzed, and ultimately relied upon by EPA and, more importantly, to meaningfully review EPA's evaluation.

[33] For the same reasons articulated in fn. 32, it is confusing as to which test runs EPA included/excluded in its distribution analysis, and EPA's lack of rationale for how it determined which test runs to use.

Third, the evaluation fails to properly address differences in typical unit operating variability by combining stack test data with PM CEMS data. Stack test data represent unit performance at a discrete point in time under full load conditions, whereas PM CEMS data provide a more comprehensive assessment of unit operating variability under all load and process conditions. These are two different data sets and should be treated independently. This is reflected in EPA's performance specification for PM CEMS, which only requires the readings to be within +/-25% of actual stack testing values two-thirds of the time (with the other one-third of the time not having any accuracy constraint) to be considered as valid readings.[34] EPA fails to explain how using such an error prone data set is justified for establishing an emissions standard. The evaluation fails to recognize that PM CEMS is not constrained to a linear correlation with direct emissions. In cases where non-linear correlations are used, an allowable +/-25% error from the correlated value could have a much larger deviation from the actual measured emissions compared to when a linear correlation is used.[35] Any emissions analysis based upon PM CEMS readings must attempt to compare unit performance in the allowable error band.

Further, any unit using a PM CEMS to demonstrate compliance with the emissions limit also must conduct annual emissions measurements under steady-state conditions, which are utilized in either a Response Correlation Audit ("RCA") or Relative Response Audit ("RRA"). The tested unit must show compliance in the short-term via stack testing measurement values and in the long-term via PM CEMS 30-day average values. For these purposes, PM CEMS data and the PM testing measurements should be treated separately and not merged as a data set. Failing to address these differences is especially problematic because EPA is proposing to require PM CEMS as the sole compliance demonstration method, as discussed further below. EPA should thus revise its current "apples-to-oranges" comparison to establish consistently achievable baseline emissions for each unit by using all available data *and* by accounting for any bias related to operating variability.

Fourth, the evaluation fails to take into consideration different control configurations — specifically, the variation in PM removal efficiencies. Some PM control technology, such as hot-side electrostatic precipitators ("ESPs"), inherently have higher particulate emissions. Similarly, depending on the coal combusted, units that utilize hydrated lime as a control technology for minimizing SO_2 and acid gases inherently have higher variability in particulate emissions. Wet flue gas desulfurization ("WFGD") controls, like Colstrip's venturi wet scrubbers, also may result in higher variability in particulate emissions. EPA should factor in these specific control configurations. EPA also should analyze more comprehensive data sets across a longer time frame — rather than using a snapshot of EGUs "demonstrating" the proposed limit during selected quarters — prior to concluding that continuous compliance with the proposed limit is achievable.

Fifth, the evaluation fails to recognize that some units have converted to natural gas co-firing. Since these units continue to have the capability to combust coal, all of their emissions data is reported as subject to MATS. However, co-firing natural gas inherently results in significantly

---

[34] *See* Appendix F, 40 C.F.R. Part 60, Procedure 2.
[35] *See* Appendix B, 40 C.F.R. Part 60, Performance Specification 11.

reduced fPM emissions, which could bias the data set low. EPA should exclude data from units that co-fire natural gas in evaluating what a revised fPM standard should be. Any proposed fPM limit that EPA establishes should be based on fPM from affected units that only combust coal.

Lastly, EPA's evaluation is replete with questionable assumptions and statements. For instance, in the technical reports developed by Sargent & Lundy ("S&L"), on which EPA relies for cost and emissions reductions assumptions, S&L acknowledges that "[b]ased on S&L's recent industry experience, the lowest filterable PM emission rates that an ESP supplier has been willing to guarantee is 0.030 lb/MMBtu for a new and/or completely rebuilt ESP."[36] Yet, the study states that "it is clear that emission levels down to 0.010 lb/MMBtu and below are achievable in most ESP applications based on the reported emissions data" despite acknowledging that the authors are unable to tie a specific performance improvement to a specific set of ESP upgrades.[37] EPA should not rely on such unsupported statements to justify a fPM limit of 0.010 lb/MMBtu.

b) EPA's fPM proposal disproportionately impacts Colstrip.

EPA's proposal to tighten the fPM limit also is arbitrary and capricious because it disproportionately impacts Colstrip. Even if EPA were correct that most units subject to the Proposed Rule would have to do nothing and that the remainder would only need to upgrade existing control technology, the same is not true for Colstrip.[38] As EPA acknowledges in the proposal, Colstrip would need to install new ESPs or FFs — and the Colstrip units, based on EPA's analysis, would be the only two units that would need to do so to comply with the proposed 0.010 lb/MMBtu fPM limit.[39]

Given that EPA's rationale for the Proposed Rule is that *existing* control technology is more effective and cost effective than was known at the time of the original MATS rule — that 91% of units already have either a FF or ESP and are meeting the proposed standard and that the rest would only need to upgrade existing control technology at relatively low cost — it simply does not follow that Colstrip should be required to install new, complex, and prohibitively expensive control technology to meet a significantly lower standard.[40] The logical conclusion that should flow from EPA's rationale (assuming that it is not flawed), is that Colstrip should upgrade its *existing* venturi wet scrubber technology to the greatest extent possible.

Instead, EPA proposed that Colstrip should meet the proposed standard by installing new FFs or ESPs at Colstrip. Below is a table summarizing the total annualized cost and the annualized

[36] Sargent & Lundy. PM Incremental Improvement Memo, Doc. ID. EPA-HQ-OAR-2018-0794-5836 at 2 (Mar. 2023). *See also* Technical Memo at PDF p. 8.
[37] PM Incremental Improvement Memo at 2.
[38] *See* Technical Memo at PDF p. 9-10.
[39] *See id.* at PDF p. 10 ("For the *one* facility with existing venturi-type WS (and without an existing ESP or FF), EPA assumes that ESP upgrades will reduce fPM emission to 1.5E-02 lb/MMBtu. To achieve the lower potential fPM standards, EPA assumes that these EGUs would require FF installation, reducing baseline fPM rates by 90% subject to a floor of 2.0 E-03 lb/MMBtu." (emphasis added)).
[40] *See* 88 Fed. Reg. at 24,868; Technical Memo at PDF p. 9-10.

cost EPA attributes for Colstrip to comply with 0.015 lb/MMBtu, 0.010 lb/MMBtu, and 0.006 lb/MMBtu fPM limits:

Table 1: Annual Costs by Potential fPM Standard

	Potential fPM Standard		
Annualized Costs	**0.015 lb/MMBtu**	**0.010 lb/MMBtu**	**0.006 lb/MMBtu**
Total of All Facilities[41]	$13-9-$19.3M	$77.3-$93.2M	$633M
Colstrip[42]	Unit 3: $843,600 Unit 4: $843,600 Total: $1,687,200	Unit 3: $18,992,866 Unit 4: $19,058,306 Total: $38,051,172	Unit 3: $18,992,866 Unit 4: $19,058,306 Total: $38,051,172

As reflected by EPA's own numbers, the annualized cost for Colstrip to comply with the proposed 0.010 lb/MMBtu fPM limit is approximately $38M, which represents 41-49% of the total annualized cost of the Proposed Rule. ***This means that EPA is asking the owners of one facility — representing 0.7% of EGUs subject to the Proposed Rule — to bear nearly 50% of the costs associated with the proposed amendment.***[43] This result is grossly unreasonable, unwarranted, and inconsistent with EPA's rationale for the Proposed Rule and should not be finalized.

c) EPA's cost effectiveness analysis is flawed.

Additionally, EPA's proposal to tighten the fPM standard is arbitrary and capricious because the Agency's cost-benefit analysis is flawed. First, EPA overestimated the benefits attributed to Colstrip if Colstrip were to comply with the 0.010 lb/MMBtu fPM limit. Below is a table summarizing the total fPM emission reductions calculated by EPA and the fPM emission reduction from Colstrip (as calculated by EPA) if Colstrip were to comply with a 0.015 lb/MMBtu, 0.010 lb/MMBtu, and 0.006 lb/MMBtu fPM limits.

[41] Table 7, Technical Memo at PDF p. 12.
[42] Appendix D, *id.* at PDF p. 80 (total annualized costs for Colstrip is calculated by summing the annualized costs for Units 3 and 4).
[43] *See id.* at PDF p. 2 (evaluating fPM rates from a total of 275 individuals EGUs with Colstrip representing two of those EGUs)

Table 2: fPM Emission Reductions by Potential fPM Standard

	Potential fPM Standard		
fPM Emission Reduction	**0.015 lb/MMBtu**	**0.010 lb/MMBtu**	**0.006 lb/MMBtu**
Total of All Facilities[44]	463 tons/yr	2074 tons/yr	6163 tons/yr
Colstrip[45]	Unit 3: 82.3 tons/yr Unit 4: 166.6 tons/yr Total: 248.9 tons/yr	Unit 3: 442.1 tons/yr Unit 4: 528.3 tons/yr Total: 970.4 tons/yr	Unit 3: 442.1 tons/yr Unit 4: 528.3 tons/yr Total: 970.4 tons/yr

As reflected above, EPA associated nearly 47% of the total fPM emission reduction for the proposed 0.010 lb/MMBtu fPM limit to Colstrip. However, that result relies on questionable assumptions. For instance, to achieve the 0.015 lb/MMBtu fPM limit, EPA assumed that Colstrip would conduct maintenance of its venturi wet scrubbers. But maintenance alone (or any other optimization measures) will not further improve the performance of Colstrip's wet scrubbers, as they are already performing at maximum optimization, as discussed above in Section II.A.[46]

Similarly, to achieve both the 0.010 lb/MMBtu and 0.006 lb/MMBtu fPM limits, EPA assumes that Colstrip will install a new FF that would "reduce[] baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu."[47] In taking the 99th percentile of the lowest quarter to describe the baseline fPM rate for each EGU, EPA assumes for Colstrip a baseline of 0.018 lb/MMBtu fPM for Unit 3 and 0.021 lb/MMBtu fPM for Unit 4.[48] ***With a 90% reduction, this means that EPA is assuming that Unit 3 would achieve 0.0018 lb/MMBtu fPM (subject to the 0.0020 lb/MMBtu fPM floor caveat) and Unit 4 would achieve 0.0021 lb/MMBtu fPM with a FF.*** But such emission rates are significantly below either the proposed 0.010 lb/MMBtu fPM limit or the more stringent 0.006 lb/MMBtu fPM limit EPA is considering.

Moreover, EPA has provided zero engineering justification for its assumption that any EGU could achieve such emission rates with FFs/baghouses, much less Colstrip's units with their unique configuration. S&L's technical reports in fact states that FF vendors would not be able to guarantee rates as low as EPA's 0.0020 lb/MMBtu fPM floor assumption. For instance, S&L state that "[w]ith the usage of more expensive fiberglass bags with a PTFE [polytetrafluroethylene] membrane coating, it is expected that 0.00375 lb/MMBtu of filterable PM emission could be achieved *but would not be guaranteed by vendors*" and "[a]s such, a best-case scenario would be

[44] Table 6, *id.* at PDF p. 11.
[45] Appendix D, *id.* at PDF p. 80 (total fPM emission reductions for Colstrip are calculated by summing the annualized costs for Units 3 and 4).
[46] *See id.*; Table 5, *id.* at PDF p. 10-12.
[47] *See id.* at PDF p. 10.
[48] *See id.* at PDF p. 4; Appendix C, *id.* at PDF p. 46.

achieving 0.005 lb/MMBtu."[49] Indeed, based on Talen Montana's discussions with consultants and vendors, it may not be possible to guarantee anything under 0.010 lb/MMBtu depending on the configuration. As a result, EPA has grossly overestimated the emission reductions from Colstrip that, coupled with EPA's unjustified assumptions, renders its cost-benefit analysis flawed. For example, EPA estimates fPM emission reductions of 970.4 tons/yr from Colstrip assuming that Colstrip will achieve emission rates of 0.0020 lb/MMBtu fPM for Unit 3 and 0.0021 lb/MMBtu fPM for Unit 4 once controls are installed. However, as discussed below, Colstrip may only attain an emission rate of 0.010 lb/MMBtu fPM, which corresponds to a reduction of 538 tons/yr using EPA's "baseline."

Second, EPA also underestimated the cost per ton of fPM reduced for Colstrip because EPA's cost effectiveness analysis fails to account for the impacts of the IRA. As EPA states in the Proposal, the Agency's estimates in the analysis "do not account for any future changes in the composition of the operational coal-fired EGU fleet that are likely to occur by 2028 as a result of other factors affecting the power sector, such as the Inflation Reduction Act (IRA), future regulatory actions, or changes in economic conditions."[50] This is problematic because it means that EPA is assuming that Colstrip Units 3 and 4 will continue to operate as baseload units for the foreseeable future.[51] But such an assumption is contrary to EPA's post-IRA IPM model, which predicts that Colstrip will shift away from operating as baseload units and its utilization will decrease. Specifically, the post-IRA IPM model — which accounts for future changes that are likely to occur *only* as a result of the IRA and *not* other factors (*e.g.*, Proposed Rule, Proposed GHG Rule) — assumes that Colstrip will:

- Through 2030, continue to operate as baseload units with an estimated combined heat input of 113 TBtu/year.[52]
- By 2040, reduce its utilization by 25% so that it is estimated to operate at a combined heat input of 85 TBtu/year.[53]
- By 2050, reduce its utilization by 88% so that it is estimated to operate at a combined heat input of 13 TBtu/year.[54]

As reflected in Attachment B, the cost effectiveness of installing new baghouses at Colstrip significantly decreases over time because of reduced utilization. Utilizing EPA's cost numbers (and presumed emission reductions), the cost effectiveness is estimated to be $39,192/ton fPM reduction in 2030 assuming baseload operation (*i.e.*, 113 TBtu/year). However, the cost

[49] PM Incremental Improvement Memo at 9 (original underline omitted, italicized emphasis added). *See also id.* at 10 ("[S]uppliers *may* be willing to provide a filterable PM guarantee of 0.005 lb/MMBtu for new baghouses with PTFE bags." (original underline omitted, italicized emphasis added)).
[50] 88 Fed. Reg. at 24,869-70.
[51] *See* Technical Memo at PDF p. 11.
[52] Post-IRA 2022 Reference Case, https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.
[53] *Id.*
[54] *Id.*

effectiveness would be $51,071/ton fPM by 2040 assuming 75% of baseload utilization and $330,026/ton fPM by 2050 assuming 12% of baseload utilization. The post-IRA IPM model predicts an 88% reduction in fPM emissions from Colstrip by 2050, as a result of the IRA *only* and *without* reductions from the Proposed Rule. Thus, by not incorporating the post-IRA IPM model into the analysis, EPA's cost effectiveness estimate for Colstrip is severely underestimated because it is premised on the Colstrip units operating at baseload utilization across a fifteen-year time horizon and fails to account for the change in utilization that Colstrip is projected to undergo by the latter part of that horizon.[55] In other words, Colstrip is projected to operate and emit less, and thus the same costs will be borne to generate fewer tons of reductions.

Third, EPA fails to account for the reduction in remaining useful life and utilization that also may result from EPA's other rulemakings targeting Colstrip, including the Proposed CCR Rule and the Proposed GHG Rule. For instance, EPA's Proposed GHG Rule, if finalized, would make it challenging for Colstrip to meaningfully operate past 2034, or even 2031, given the proposed 20% capacity factor limit for near-term units in the Proposed GHG Rule (assuming that units would need to adopt that limit from 2031 to 2034). But the Proposed Rule would require the Colstrip owners to spend hundreds of millions of dollars to install FFs or ESPs by 2027 or 2028, only to potentially shut down or seriously curtail operations by 2031 due to the Proposed GHG Rule. In considering the cost effectiveness of the rule, EPA should have considered that the costs to upgrade Colstrip may only be spread over three to four years. This would yield astronomically high annualized costs. Moreover, it is highly improbable that the Colstrip owners would shell out those huge sums of money to operate for three or four more years, as the owners would not be able to recoup those costs. Colstrip shutting down prematurely would have far-reaching ramifications on Montana's economy and the surrounding region and grid stability and transmission, as discussed in Section II.B. — none of which EPA considered.

B. <u>The Cost for Colstrip to Comply with the Proposed 0.010 lb/MMBtu fPM Limit is Exorbitant and Requires Significant Time to Install, Test, and Implement the Controls</u>.

Talen Montana retained Burns and McDonell ("B&M"), an engineering consulting firm, to evaluate the cost and feasibility of control technologies available to Colstrip to comply with the proposed 0.01 lb/MMBtu fPM limit. Working with equipment vendors, B&M evaluated the cost and feasibility of a number of controls, including an ESP or a FF upstream of Colstrip's existing wet scrubbers, a wet ESP, and an ESP or a FF downstream of Colstrip's existing wet scrubbers. For the purposes of these comments, B&M conducted a high-level feasibility and cost review that would need to be refined with additional engineering. Actual costs when compared to this level of estimate could be as much as 50% higher than those projected here. Sufficient time was not

[55] *See* Technical Memo at PDF p. 10.

available during the comment period to further refine the feasibility and costs, and EPA rejected Talen Montana's request for more time to undertake additional efforts.[56]

B&M's estimates for the two units combined are summarized below (see Attachment C for the memorandum from B&M which contains a detailed summary of estimates). The first table is how B&M estimates costs, including cost escalation during construction. The second table is meant to be more aligned with how EPA estimates costs, which leads to underestimates:

[56] *See* Talen Montana's Request for Extension of the Comment Period on the National Emissions Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, Doc. ID. EPA-HQ-OAR-2018-0794-5880, submitted May 25, 2023 (denied on June 12, 2023).

Table 3: Annual Costs of Control Options at Colstrip to Meet the Proposed 0.010 lb/MMBtu fPM Limit (B&M Class 5 Feasibility Estimates)

		Installed Capital Cost	*Annualized Cost of Controls*
Total (EPA)[57]			$77.3-$93.2M
Colstrip[58]	**Baghouse (EPA)[59]**		$38,051,172
	Upstream ESP (B&M)	$486.0M	$87.4M
	Upstream FF (B&M)	$404.9M	$78.0M
	Wet ESP (B&M)	$744.5M	$104.9M
	Reheat ESP (B&M)	$263.5M	$41.8M
	Reheat FF (B&M)	$351.2M	$56.5M

Table 4: Annual Costs of Control Options at Colstrip to Meet the Proposed 0.010 lb/MMBtu fPM Limit (B&M Estimates Using EPA Cost Approach)

		Installed Capital Cost	*Annualized Cost of Controls*
Total (EPA)[60]			$77.3-$93.2M
Colstrip[61]	**Baghouse (EPA)[62]**		$38,051,172
	Upstream ESP (B&M)	$406.1M	$77.8M
	Upstream FF (B&M)	$338.3M	$70.1M
	Wet ESP (B&M)	$622.2M	$90.4M
	Reheat ESP (B&M)	$220.2M	$36.6M
	Reheat FF (B&M)	$293.4M	$49.7M

[57] Table 7, Technical Memo at PDF p. 12 (for all EGUs subject to the Proposed Rule).
[58] Cost estimates are based on the following assumptions, scope, and other cost factors. Assumptions include: 85% capacity factor, $15/ton disposal, $200/ton lime, $45/MW power, 15-year life, and 8.25% prime rate. Scope includes: ductwork, foundations, control device, electrical (percent based), no fans, no stack modifications, and ash and lime silos and slurring/feed for upstream control options. Other cost factors include: 5% indirect costs, 8% engineering cost, 5% escalation during construction, 15% contingency costs, and 0% owners' cost.
[59] Appendix D, *id.* at PDF p. 80 (total annualized costs for Colstrip is calculated by summing the annualized costs for Units 3 and 4).
[60] Table 7, Technical Memo at PDF p. 12 (for all EGUs subject to the Proposed Rule).
[61] Cost estimates are based on the following assumptions, scope, and other cost factors. Assumptions include: 85% capacity factor, $15/ton disposal, $200/ton lime, $45/MW power, 15-year life, and 8.25% prime rate. Scope includes: ductwork, foundations, control device, electrical (percent based), no fans, no stack modifications, and ash and lime silos and slurring/feed for upstream control options. Other cost factors include: 0% indirect costs, 8% engineering cost, 0% escalation during construction, 10% contingency costs, and 0% owners' cost.
[62] Appendix D, *id.* at PDF p. 80 (total annualized costs for Colstrip is calculated by summing the annualized costs for Units 3 and 4).

As reflected above, B&M's estimates of annualized costs are significantly higher than EPA's $38M estimate[63] for a new FF at Colstrip, ranging from $41.7M to $104.9M (using B&M's Class 5 Estimate) and $36.6M to $90.3M (using EPA's approach), assuming that Colstrip is just able to meet the proposed 0.010 lb/MMBtu fPM limit.

Further, the cost effectiveness of each of the control options that B&M evaluated are below, where the first B&M column is based on a fPM baseline of 0.022 lb/MMBtu, which represents Colstrip's average fPM emission rate in 2022, and the second B&M column is based on a fPM baseline of 0.0195 lb/MMBtu, which represents the average of the EPA's fPM baselines for Colstrip's Units 3 and 4. The B&M estimates are calculated using EPA's cost approach.[64]

Table 5: Cost Effectiveness of Control Options at Colstrip

		EPA[65]	***B&M 0.022 lb/MMBtu fPM baseline***	***B&M 0.0195 lb/MMBtu fPM baseline***
Colstrip	**Baghouse**	$39,192/ton		
	Upstream ESP		$114,900/ton	$145,000/ton
	Upstream FF		$103,200/ton	$130,300/ton
	Wet ESP		$133,100/ton	$168,000/ton
	Reheat ESP		$53,900/ton	$68,000/ton
	Reheat FF		$73,200/ton	$92,400/ton

As reflected above, the cost effectiveness for Colstrip to install the various controls are significantly higher than EPA's estimate of $39,192/ton (see Section III.A.2.c, assuming baseload operation), ranging from $73,156/ton to $133,104/ton (using the actual 0.022 lb/MMBtu fPM baseline) and from $68,114/ton to $168,132/ton (using an average of EPA's fPM baseline for the units). In the B&M scenarios, the cost per ton is calculated assuming that the units will just be able to achieve 0.010 lb/MMBtu after controls based on the technical review to date, as opposed to EPA's unrealistic assumptions of a 90% reduction in fPM down to 0.002 lb/MMBtu.

At this preliminary stage, the downstream ("Reheat") options are the most cost-effective. The upstream options, and wet ESP option, are even more costly, and come with additional technical challenges, as outlined in the B&M memorandum attached as Attachment C. Despite the lower cost of the Reheat ESP compared to the Reheat FF, the Reheat ESP comes with more technical challenges in meeting the 0.010 lb/MMBtu standard.[66] The Reheat FF has fewer technological challenges and could be the preferred alternative should Colstrip retrofit to comply with the Proposal. However, with an annualized cost of $56.5 M (using B&M's Class 5 estimates)

---

[63] Note that EPA fails to provide meaningful information as to how annualized control costs were estimated, how capital costs were specifically calculated for Colstrip, or what specific control configurations were accounted for in the estimates. This has made it difficult for Talen Montana to fully comment on EPA's cost estimates.
[64] *Supra* fn. 61.
[65] *See* Attachment B.
[66] *See* Attachment C.

or $49.7M (B&M's estimates using EPA's cost approach), and with a limited lifespan and limited generation to recoup the costs, it is far more likely that Colstrip would suffer a premature retirement with the potential for serious economic disruption and impacts on grid reliability and transmission.

C. Should EPA Finalize the Proposed 0.010 lb/MMBtu fPM Limit, EPA Should Create Additional Subcategories.

EPA should not finalize the 0.010 lb/MMBtu fPM limit. But should EPA do so, the Agency should establish subcategories so that it accounts for Colstrip's unique design and circumstances. Specifically, EPA should establish a subcategory for coal-fired units that use wet scrubbers to address both SO_2 and PM, and that do not have ESPs or FFs, where the fPM limit for those units is no lower than 0.025 lb/MMBtu pursuant to its authority under 42 U.S.C. § 7412(c)(5). As discussed above, application of the 0.010 lb/MMBtu fPM standard to Colstrip is not appropriate or warranted. At most, EPA should require Colstrip to optimize its existing control technology, consistent with the burden borne by other EGUs, as evaluated by the Agency. While Talen Montana believes that its efforts to reduce fPM have already been optimized, a limit of 0.025 lb/MMBtu fPM may be more achievable, especially as compared to the 0.010 lb/MMBtu fPM limit, as it would at least provide Colstrip an opportunity to try to meet the limit without new control technology. It also would provide for a more stringent limit for Colstrip, with additional emission reductions, and would be more appropriate for Colstrip given its unique circumstances.

As an additional alternative, EPA should establish a subcategory with units making an enforceable commitment to retire, where the fPM limit remains at 0.03 lb/MMBtu through retirement.[67] This would be in line with how EPA is providing lead time for older sources in other rulemakings.[68] Creating a subcategory in the MATS rule for units committing to retire would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, deliberating whether to install controls and continue operation longer than planned to recoup investments in the controls.

Here, EPA should create a retirement subcategory allowing units to continue to meet the existing 0.03 lb/MMBtu fPM standard so long as they opt-in to the retirement subcategory within 18 months after finalization of the rule, with a retirement date no later than December 31, 2035 (and where continued operation after 2035 would later be permitted if (i) the unit is essential to maintain regional grid reliability, as determined by the Western Regional Adequacy Program, Regional Transmission Organizations, Independent System Operators, North American Electric Reliability Corporation, or other similar system reliability authorities; or (ii) or if EPA determines

[67] A unit should qualify for the retirement subcategory as long as it commits to cease burning coal by the proposed deadline of December 31, 2035.

[68] *See e.g.*, Proposed GHG Rule, 88 Fed. Reg. 33,240, 33,245 (May 23, 2023) (near-term retirement units); Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023).

that additional time is required for transition to renewable or clean energy generation).[69] This would provide units another compliance option and needed flexibility.

D. EPA Should Retain the fPM Emission Monitoring Options.

EGUs that do not qualify for the low emitting EGU program currently demonstrate compliance with the fPM standard by conducting quarterly performance testing (*i.e.*, quarterly stack testing), using a PM continuous parameter monitoring system ("CPMS"), or using a PM CEMS.[70] EPA is proposing to eliminate the quarterly stack testing and CPMS options for all coal-fired EGUs — specifically, requiring all coal-fired EGUs to use PM CEMS "[a]fter considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and on the measurement capabilities of PM CEMS, as well as other benefits of using PM CEMS, which include increased transparency and accelerated identification of anomalous emissions."[71] According to EPA, PM CEMS data "supply real-time, quality-assured feedback that can lead to improved control device and power plant operation, which, in turn, can lead to fPM emission reductions."[72]

Talen Montana disagrees with EPA's conclusions and strongly believes that sound engineering approaches using control device operating parameters, such as those found in EPA's required compliance assurance monitoring ("CAM") plans achieve the same ultimate objective of fPM emission reductions. It is unclear how adding another measurement system, particularly given the challenges with PM CEMS as described below, would be cost-effective. Talen Montana urges EPA to retain the option for quarterly stack testing (without any changes to testing frequency) and the CPMS option for all coal-fired EGUs.

1. General Challenges with PM CEMS

EPA should retain the quarterly stack testing and PM CPMS options — particularly if the Agency intends to finalize the proposed 0.010 lb/MMBtu fPM emission limit — to afford entities flexibility in demonstrating compliance with the more stringent limit. Currently, two-thirds of existing EGUs have chosen to demonstrate compliance via the quarterly stack testing approach, and EPA should continue to retain that option in light of the difficulties with using PM CEMS. EPA justifies the proposed requirement to use PM CEMS based on cost, but the Agency understates the costs of PM CEMS and significantly overstates stack testing costs.[73] The costs associated with installing, maintaining, and operating a PM CEMS far outweigh the costs of demonstrating compliance through stack testing, as discussed below.

[69] It makes sense for units retiring in this time frame to be allowed to continue operations without installation of new controls because the annualized costs for an eight-year period (*i.e.*, installation in the 2027-2028 time period and retirement by the end of 2035) would be excessive. For example, the annualized costs for the reheat FF with an eight-year life would be $76.6M versus $56.5M with a 15-year life.
[70] *See* 40 C.F.R. § 63.10011(b).
[71] *See* 88 Fed. Reg. at 24,857.
[72] *Id.* at 24,872.
[73] *Id*.

In addition, use of PM CEMS may not be appropriate for all coal-fired units given the challenges associated with: (i) meeting the Quality Assurance-Quality Control ("QA-QC") criteria required under Procedure 2; and (ii) establishing the correlation curve using Performance Specification 11 ("PS-11"). First, when a PM CEMS fails to meet the QA-QC criteria required under Procedure 2, the collected data is considered out-of-control and is no longer considered valid.[74] Because the measured emissions values are dependent upon laboratory analysis, an owner/operator has no real time indication that its EGU might have failed the required QA-QC criteria until several weeks after the testing has been completed. This can result in hundreds of hours of monitor downtime being created retroactively after the QA-QC criteria failure has been identified. Monitor downtime is required to be reported as a deviation under the MATS rule, and most states have minimum data availability requirements that could result in enforcement actions. At the more stringent fPM criteria of 0.010 lb/MMBtu (or 0.006 lb/MMBtu), the likelihood of out-of-control periods increases. This downtime is not reflective of poor maintenance or operation but rather the difficulties associated with the required calibration procedure at such low emission levels. Thus, in conjunction with this rulemaking, EPA should include additional provisions in Appendix C of 40 C.F.R. Part 63, Subpart UUUUU to mitigate the effects of this downtime, such as provisional data periods following a failed RRA or RCA. Moreover, there currently is no calibration procedure available that can accurately verify continuous measuring of fPM at levels as low as 0.010 lb/MMBtu, much less 0.006 lb/MMBtu.[75]

EPA attempts to address these issues by proposing to amend Table 2 of 40 C.F.R. Part 63 Subpart UUUUU to require sample volumes of at least 4 dscm per run, rather than at least 1 dscm per run.[76] While the additional sample volume will reduce measurement uncertainty, it does not address the unit and control device operating variability that occurs during correlation testing that would make it difficult to achieve the distinct PM test conditions required under PS-11 and Procedure 2. In addition, when developing the initial correlation curve or conducting ongoing RCAs, emissions controls are de-tuned to simulate upset conditions and to achieve dust loadings at mid- (25-75% of the maximum expected concentration) and high- (50-100% of the maximum expected concentrations) levels.[77] For units equipped with WFGD systems, expanding the test runs to collect 4 dcsm of sample volume significantly increases the flyash carryover to the scrubber.[78] This off-spec material is then required to be landfilled instead of beneficially reused.

---

[74] *See* Appendix F, 40 C.F.R. Part 60, Procedure 2.

[75] *See* Nicklin, D. et. al., "Techniques to measure particulate matter emissions from stationary sources: A critical technology review using Multi Criteria Decision Analysis (MCDA)," *Journal of Environmental Management*, 296:18-20 (2021).

[76] *See* MATS RTR Rule Text Redline Strikeout document (final) ("Redline Final"), posted on Apr. 25, 2023, at PDF p. 86, 89, 91, 96, 98, Doc. ID. EPA-HQ-OAR-2018-0794-5831. *See also* 88 Fed. Reg. at 24,873-74.

[77] Trying to simulate different ranges of particulates created for test activities often has unintended consequences on the FGD's performance that can take days to normalize and clean up so that the equipment resumes performing as designed. Any additional ash carryover into the FGD increases the opportunity to blind the FGD such that the only recovery is to shut the unit down to add lime or to dump the ash into a storage tank because the material can no longer be stored in the onsite landfill as the chloride content of the sludge, at that point, has become too high.

[78] Ash reinjection may be not feasible for some sources due to stratification issues or ash drop-out effects.

Furthermore, it can take days to weeks for the scrubber chemistry to again reach optimal, steady-state conditions; and maintaining optimal scrubber chemistry is needed to ensure effective removal of mercury emissions. The increased particulate loading will physically impact the equipment and degrade the scrubber's performance, such as: scaling inside the scrubber vessel; plugging spray headers; causing buildup on mist eliminators; and eroding booster and ID fan blades and absorber recirculating pumps.

Second, PM CEMS require the use of PS-11 to establish a correlation curve.[79] For the PS-11 PM CEMS correlation test, a minimum of 15 sets of reference method testing must be conducted that are evenly spaced over three different levels of PM mass concentration by varying process operating conditions, by varying PM control device conditions, or by means of PM spiking.[80] If it is not possible to obtain three distinct levels of PM concentration, zero point testing may be used to perform correlation testing over the maximum range of PM concentration that is practical for the PM CEMS.[81] Each run requires roughly three to four hours, and most sources conduct 18 to 20 test runs for a robust correlation.[82] Barring unpredictable circumstances, based on the proposed sampling time, PS-11 may require seven to ten days to complete. Additional time likely will be needed to maintain the distinct PM test conditions that are required. Sources also will require accurate, preliminary test results to evaluate each test condition and may even need to obtain final results before concluding the test program, which further extend the length and cost of the tests. These activities increase the cost of MATS compliance and overall EGU operation, as well as disrupt the normal operation of the EGU. Ongoing PM CEMS correlation testing with injection of media in the effluent to artificially raise emission levels costs at least $250,000 per test evolution at one source, and testing is required by MATS once every three years. For Colstrip's Units 3 and 4, PM CEMS would cost approximately $136,000/year, whereas quarterly MATS PM stack testing costs approximately $24,000/year. Thus, EPA may have significantly underestimated annual costs associated with a PM CEMS (from $18,111 to $95,397 depending on type) and overestimated annual costs associated with stack testing ($85,127), particularly when specific control configurations are taken into account.[83] Furthermore, the excessive costs of installing and maintaining PM CEMS become even more onerous if required on a unit with limited remaining life (see earlier discussion on how other rules may force retirement, cessation of coal, or decreased capacity factors, or if an early retirement subcategory is created).

More importantly, EPA has failed to show how correlations can be developed on data sets where the upper end of the emissions testing is capped at 0.010 lb/MMBtu fPM following PS-11 requirements. Emissions levels are supposed to be evenly distributed between the low, mid, and high PM emission levels. Even when allowing for a low-emitting unit to use a zero point in the correlation, a correlation still needs data variation to be a valid regression model. By limiting the

---

[79] *See* Appendix B, 40 C.F.R. Part 60, Performance Specification 11.
[80] *See id.*
[81] *See id.*
[82] *See id.*
[83] 88 Fed. Reg. 24,872-73.

dataset — pursuant to the proposed 0.010 lb/MMBtu fPM limit — EPA needs to establish that the PS-11 correlation will still be valid at such low levels.

2. Colstrip's Challenges with PM CEMS

Colstrip has utilized PM CEMS as a particulate control performance indicator in its PM CAM Plan since 2014. The initial PM CEMS were a light scattering technology that encountered times when they did not accurately indicate particulate emissions from the wet venturi scrubber at Colstrip Units 3&4. In September 2020, the PM CEMS were changed to the MSI BetaGuard 3.0 PM CEMS. The BetaGuard PM CEMS has performed better than the light scattering technology at Colstrip; however, it still exhibits variability that would not be acceptable to be used as a continuous compliance monitor. When compared to the quarterly MATS PM compliance test results, the BetaGuard PM CEMS has provided mg/m^3 values that varied from the RM5 mg/m^3 value by -24% to +31%. Talen Montana believes this range of variability with the PM CEMS is not acceptable for use as a compliance monitor, but its use as part of a PM CAM Plan like Colstrip utilizes, is reasonable.

The PM CAM Plan is a requirement under Colstrip's Title V Operating Permit to help ensure compliance to the particulate standard utilizing performance indicators and an operational parameter. The performance indicators include opacity monitoring and PM CEMS, and the operational parameter is scrubber plumb bob delta P.

PM CEMS requirements under Colstrip's PM CAM Plan are robust and include:

- Installation per manufacturer's standards.
- Daily zero and span checks using manufacturer's standards.
- Initial correlation based on three levels (zero, normal operations, and at scrubber operations that increase PM but not at a level that puts Colstrip's Title V requirements at risk). This initial correlation used three RM5 runs at normal operations and two RM5 runs at the higher PM level. This correlation relates PM CEMS mg/m^3 to RM5 mg/m^3.
- A PM CEMS CAM Plan excursion limit in terms of mg/m^3 is established.
- A PM CEMS CAM Plan excursion requires a prompt investigation to identify and correct the condition, followed by a RM5 test to confirm compliance with the particulate standard.
- On a quarterly basis, one RM5 test (comprised of three runs) will be conducted to update the initial correlation. If the result from the average of the three runs differs

from the initial correlation by 25% or more of the CAM Plan excursion limit, then the initial correlation will be repeated.

- An on-going PM CEMS correlation adjustment will be made quarterly based on the correlation from all RM5 test data.

- PM CEMS daily averages are submitted to MDEQ on a quarterly basis.

Given Colstrip's experience with the use of PM CEMS as a performance indicator, which shows that the CEMS results are highly variable and not reliable, EPA should not finalize the CEMS requirement in the Proposed Rule. If EPA does finalize the CEMS requirement, EPA should: (i) carve out units like Colstrip Units 3 and 4 that already have a CAMS plan that utilizes performance indicators and operational parameters to ensure compliance with the particulate standard; and (ii) not require PM CEMS for units that would only be subject to MATS for a limited time after the effective date of the final rule.

IV. CONCLUSION

Talen Montana appreciates the opportunity to submit comments on the Proposed Rule. Talen Montana respectfully requests that EPA consider the recommendations above to ensure that the Agency accounts for Colstrip's unique design and circumstances, as well as to account for the prohibitive costs that Colstrip faces if it were forced to comply with the proposed fPM limit. Colstrip is vital to Montana, and premature retirement could jeopardize Montanans' access to affordable and reliable electricity, especially during extreme weather conditions.

Dated: June 23, 2023

Respectfully submitted,

Thomas Weissinger
Sr. Director – Environmental
Talen Energy
thomas.weissinger@talenenergy.com

ATTACHMENT A

Please see native Excel file “ATTACHMENT A” accompanying Talen Montana’s comments.

ATTACHMENT B

The following table summarizes how the cost effectiveness of installing a new baghouse at Colstrip was calculated using EPA's post-IRA IPM model. The table was prepared by Trinity Consultants, which Talen Montana retained for the purposes of preparing comments on the Proposed Rule.

Colstrip New Baghouse Cost Effectiveness

Scenario	Unit	Heat Input (MMBtu/yr)	Current FPM Emission Factor (lb/MMBtu)	FPM Emissions (tpy)	% Reduction in FPM without Proposed Rule	New Baghouse Cost ($/yr)	FPM Emission Factor with New Baghouse (lb/MMBtu)	FPM Emissions with New Baghouse (tpy)	FPM Emissions Reduction from New Baghouse (tpy)	New Baghouse Cost Effectiveness ($/ton)
EPA Proposed Emission Reductions (Baseload Operation)	3	55,255,556	0.018	497.3		18,992,866	0.0020	54.7	442.6	42,912
	4	55,904,762	0.021	587.0		19,058,306	0.0021	58.7	528.3	36,075
	Total	111,160,317		1084.3		38,051,172		113.4	970.9	39,192
Emission Reductions Using 2040 Base Case	3	42,374,312	0.018	381.4		18,992,866	0.0020	42.0	339.4	55,957
	4	42,925,688	0.021	450.7		19,058,306	0.0021	45.07	405.6	46,982
	Total	85,300,000		832.1	23%	38,051,172		87.0	745.1	51,071
Emission Reductions Using 2050 Base Case	3	6,557,338	0.018	59.0		18,992,866	0.0020	6.5	52.5	361,602
	4	6,642,662	0.021	69.7		19,058,306	0.0021	6.97	62.8	303,606
	Total	13,200,000		128.8	88%	38,051,172		13.5	115.3	330,026

Scenarios. The scenarios presented for calculating the cost effectiveness of installing a baghouse at Colstrip are: (i) based on the utilization and heat input predicted EPA's post-IRA IPM model from present to 2050;[84] (ii) based on EPA's "baseline" for Colstrip, which represents the 99th percentile of the lowest

[84] Final Version of the RIA [Regulatory Impact Analysis] for the Proposed EGU MATS RTR, Doc ID. EPA-HQ-OAR-2018-0794-5837; Post-IRA 2022 Reference Case, https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.

quarter among the 2017, 2019, and 2021 data EPA evaluated;[85] and (iii) based on EPA's assumption that installing a baghouse would "reduc[e] baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu.[86]

Heat Input (MMBtu/yr). Heat input is calculated by EPA's Post-IRA 2022 Reference Case.[87]

Current FPM Emission Factor (lb/MMBtu). Current fPM emission factor is EPA's "baseline" for Colstrip, which represents the 99th percentile of the lowest quarter among the 2017, 2019, and 2021 data EPA evaluated.[88]

FPM Emissions (tpy). fPM emissions are calculated by multiplying the Heat Input (MMBtu/yr) by the Current FPM Emission Factor (lb/MMBtu) and diving by 2000 lb/ton.

New Baghouse Cost ($/yr). New baghouse cost is EPA's annualized cost estimate for Colstrip to achieve compliance with the proposed 0.010 lb/MMBtu fPM limit via a new baghouse.[89]

FPM Emission Factor with New Baghouse (lb/MMBtu). fPM emission factor with new baghouse is based on EPA's assumption that installing a baghouse would "reduc[e] baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu.[90]

FPM Emissions with New Baghouse (tpy). fPM emissions with new baghouse are calculated by multiplying the Heat Input (MMBtu/yr) by the fPM New Baghouse Emissions factor (lb/MMBtu) and then diving by 2000 lb/ton.

FPM Emissions Reduction from New Baghouse (tpy). fPM emission reduction from new baghouse is calculated by subtracting fPM emissions with new baghouse (tpy) and fPM emissions (tpy).

New baghouse cost effectiveness ($/ton). New baghouse cost effectiveness is calculated by dividing new baghouse cost ($/yr) by fPM emissions reduction from new baghouse (tpy).

---

[85] *See* Technical Memo at PDF p. 4.
[86] *See id.* at PDF p. 10.
[87] Post-IRA 2022 Reference Case, https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case.
[88] *See id.* at PDF p. 4.
[89] Appendix D, *id.* at PDF p. 80.
[90] *See id.* at PDF p. 10.

ATTACHMENT C

June 23, 2023

Mr. Gordon Criswell
Talen Montana
580 Willow Ave, PO Box 38
Colstrip, MT 59323

Re: Talen Energy Colstrip/ Mercury and Air Toxics Standards (MATS) Analysis

Dear Mr. Criswell:

Talen Montana, LLC (Talen) engaged Burns & McDonnell Engineering Company, Inc. (BMcD) to assist it in evaluating the potential cost impacts of complying with the potential particulate limits in EPA's proposed MATS rule. The scope of work included the following:

1. Evaluate the proposed filterable particulate matter limit of 0.01 lb fPM/mmBtu and evaluate what particulate control technologies could maintain the limit at Colstrip.
2. Provide an AACE Class 5 estimate of the necessary capital improvements and operations/maintenance costs.

Background Information

The Colstrip units being evaluated are two approximately 740 MW units (net) that fire PRB coal and utilize a plumb bob wet scrubber to simultaneously remove filterable particulate and sulfur dioxide (SO_2) from the flue gas. This approach has the advantage of using the alkalinity inherent to PRB fly ash as reagent to help remove SO_2. However, this control technology is not as effective at removing fine particulate matter (fPM) as more modern particulate control technologies. The system was originally designed to achieve an emission rate of 0.05 lb fPM/mmBtu at a plumb bob pressure drop of 17".

Over the years the Colstrip plant has worked with scrubber consultants and engineers to improve the fPM removal ability of the scrubber. Changes and upgrades have increased the pressure drop to the system maximum across the scrubber's plumb bob, optimized mist eliminators, and installed flow distribution plates to optimize scrubber performance. Beyond the scrubber, Colstrip has made operational changes to improve the fPM removal including improving boiler wall cleaning to impact the size of the fPM and increase removal across the scrubber, implemented a combustion optimization system, and performed preventative maintenance on the coal mills to maintain the coal grind size and thus the resulting fPM size. However, even with these previous scrubber upgrades, operational changes and maintenance practices focused on fPM removal, the best single quarterly fPM compliance test the unit has achieved (not maintained) is 0.017 lb/mmBtu.

The upgraded system typically operates between 0.020 and 0.027 lb fPM/mmBtu. The average quarterly fPM compliance tests for 2022 was 0.022 lb/mmBtu. These rates are in compliance with the current limit of 0.030 lb fPM/mmBtu but would not be in compliance with the proposed MATS rule. The proposed MATS rule would reduce the fPM limit to 0.010 lb fPM/mmBtu.

Particulate Control Technology Discussion

Potential Particulate Control Options to Achieve New MATS fPM Limit

BMcD evaluated several options to reduce fPM at Colstrip. These options include dry/wet electrostatic precipitators (ESP) and baghouses/fabric filters (FF). The traditional location for a dry ESP or FF is between the air heater outlet and the scrubber. A wet ESP would be located after the scrubber systems while the flue gas is saturated. Colstrip Units have a feature that is uncommon at wet scrubbed United States power plants. After each scrubber vessel there is a reheat system that warms the flue gas approximately 60°F which results in a 'dry' (non-saturated) flue gas. This situation creates the opportunity to utilize an ESP or FF downstream of the scrubber provided that the reheat system is operational.

Burns & McDonnell (BMcD) discussed these different conditions with Southern Environmental Inc. (SEI) – an equipment supplier – and requested budgetary pricing for each option as SEI can supply all of these technologies. SEI indicated they believe that all of these options can achieve the proposed 0.010 lb fPM/mmBtu emission rate. However, guaranteeing that these rates can be continuously maintained at the stack is not certain for all technologies. We identify a few technological challenges to consider when evaluating these technologies below:

ESP/FF Located Upstream of Scrubber

If the fPM control device is installed upstream of the scrubbers, there is a question of whether the scrubbers will remove or re-introduce fPM into the flue gas. An ESP or FF upstream of the scrubber can be guaranteed to maintain 0.010 lb fPM/mmBtu at the particulate control device outlet. Nearly all of the fPM passing through the scrubber is particulate smaller than 2.5 microns ($PM_{2.5}$) as the scrubber is excellent at removing larger particulates but not great at removing smaller particulates. If an ESP or FF is installed upstream of the scrubber, all of the PM entering the scrubber will be $PM_{2.5}$and the scrubber will do little to reduce the $PM_{2.5}$ concentrations. Also, since the existing scrubbers use the alkalinity inherent to PRB fly ash as reagent to help remove SO_2, fly ash that is collected in the ESP/FF would have to be reintroduced to the scrubber for SO_2 removal and this fly ash could be re-emitted as particulate after the scrubber. Therefore, this evaluation has assumed that additional lime will be used in lieu of fly ash to control SO_2 emissions. This does not eliminate the risk the scrubbers could re-emit fPM but does reduce the risk.

Wet ESP

A wet ESP downstream of the scrubber can be guaranteed to maintain 0.010 lb fPM/mmBtu at the particulate control device outlet/stack inlet. However, the flue gas entering the scrubber must be saturated and the stack is not designed for wet flue gas. The flue gas would need to be captured prior to the existing reheat system, routed to the wet ESP and then either routed back to the existing reheat system or through a new reheat system and fan. Because of the complexity of the tie in and the fact the wet ESP and reheat system would need to be made out of high alloy to address corrosion; the cost estimate demonstrates this is the most expensive option.

ESP/FF Located Downstream of Scrubber

An ESP or FF downstream of the scrubber is expected to maintain 0.010 lb fPM/mmBtu. A FF can be guaranteed to maintain 0.010 lb fPM/mmBtu if the flue gas is maintained at least 30° above the dew point. This is critical because if the bags in the fabric filter become wetted for even a short period, the bags could be damaged catastrophically and fail to perform. This requirement could be challenging if there is an upset in the reheat system or any time steam may not be available.

An ESP can likely be guaranteed to maintain 0.010 lb fPM/mmBtu; however, there is some concern due to the fPM particle size in this location. ESP systems can remove $PM_{2.5}$ and smaller particles. However, it is more difficult to remove the smaller particles than the larger particles. Further evaluation or testing maybe required for a guarantee to be provided. The advantage of a dry ESP in this location is a dry ESP is not as susceptible as a FF to wet flue gas conditions. The dry ESP cannot operate in saturated flue gas, and continuous operation in saturated conditions would damage the ESP, but short-lived incidents with exposure to saturated flue gas are not expected to catastrophically damage the ESP.

Cost Estimate for Particulate Control Technology

Burns & McDonnell produced AACE Class 5 estimates for these control technologies based on the 'flange to flange' budgetary price information SEI shared and BMcD's previous experience in building up the fully-installed cost of such projects. The estimated costs are intended to include new ductwork, foundations, support steel, insulation, ash piping, electrical upgrades, new ash silos, new carbon injection systems, and (as applicable) new lime silos and feed systems. The costs do not include new fans, stack modifications, taxes, water treatment, or significant demolition. The Class 5 estimates presented here include: indirects, engineering, escalation during the project, and contingency. The cost estimating method favored by the EPA differs from typical industry cost estimates. Key differences of the EPA cost estimating method include removal of indirect costs and all escalation, and reducing the contingency to 10%. The Class 5 estimates we prepared, and the EPA cost estimates do not include Owners costs or an EPC fee.

The capital cost estimates provided are considered AACE Class 5 feasibility estimates and are provided in 2023 dollars unless indicated otherwise. The estimates were built up using heavy construction cost data from RSMeans, vendor input for major equipment, and in-house information from other projects. Engineering, Construction Management, Start-Up, and Contingency are based on percentages of the total direct cost for these Class 5 estimates. All sales taxes are excluded from the estimates. Talen should not use these estimates to establish the project budget as they are only intended to assist in selecting the preferred solution(s) at the site. The selected alternative(s) should be investigated further, with additional design and more detailed quantity buildup completed along with soliciting local contractors for labor pricing prior to establishing the project budget.

BMcD's estimates, analyses, and recommendations contained in this email are based on professional experience, qualifications, and judgment. BMcD has no control over weather; cost and availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology; and other economic or political factors affecting such estimates, analyses, and recommendations. Therefore, BMcD makes no guarantee or warranty (actual, expressed, or implied) that actual results will not vary, perhaps significantly, from the estimates, analyses, and recommendations contained herein.

In the preparation of this, information provided by Talen was used by BMcD to make certain assumptions with respect to conditions that may exist in the future. While BMcD believes the assumptions made are reasonable for the purposes of this study, BMcD makes no representation that the conditions assumed will, in fact, occur. In addition, while BMcD has no reason to believe that the information provided by Talen, and on which this report is based, is inaccurate in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

Cost Summary

We prepared the following cost summary of the various options. Table 1 is a summary of key assumptions while Tables 2-5 are the costs summarized and levelized to dollars per ton. Tables 2 and 4 assume the baseline is the 2022 average emission rate of 0.022 lb fPM/mmBtu while Tables 3 and 5 assume the average emission rate the EPA used in the MATS evaluation of Colstrip (0.0195 lb fPM/mmBtu).

Table 1: Summary of Capital and O&M Costs

Capacity Factor:	85%
Life, years	15
Cost of Money, %	8.25
Capital Recovery Factor	0.118619
Property Taxes, Insurance	0
Disposal cost, $/ton	15
Power cost, $/MW	45
Lime cost, $/ton	200

Table 2: Summary of Capital, O&M and Levelized Costs for Class 5 Estimate Method, 2022 Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
PM-10 Control Alternative (Ranked by PM-10 Rate)	**PM Removal Efficiency** % (Note B)	**Emissions** Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	**Economic Impacts** Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	54.55	0.010	152	566	679	486.0	29.8	87.4	128,700
Upstream FF	54.55	0.010	152	566	679	404.9	29.9	78.0	114,900
Wet ESP	54.55	0.010	152	566	679	744.5	16.6	104.9	154,500
Reheat ESP	54.55	0.010	152	566	679	263.5	10.5	41.8	61,600
Reheat FF	54.55	0.010	152	566	679	351.2	14.9	56.5	83,200
2022 Baseline (Scrubber)		0.022	334	1245		N/A	N/A	N/A	N/A

Table 3: Summary of Capital, O&M and Levelized Costs for Class 5 Estimate Method, EPA Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
PM-10 Control Alternative (Ranked by PM-10 Rate)	**PM Removal Efficiency %** (Note B)	**Emissions** Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	**Economic Impacts** Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	48.72	0.010	152	566	538	486.0	29.8	87.4	162,500
Upstream FF	48.72	0.010	152	566	538	404.9	29.9	78.0	145,000
Wet ESP	48.72	0.010	152	566	538	744.5	16.6	104.9	195,000
Reheat ESP	48.72	0.010	152	566	538	263.5	10.5	41.8	77,700
Reheat FF	48.72	0.010	152	566	538	351.2	14.9	56.5	105,000
2022 Baseline (Scrubber)		0.0195	296	1103		N/A	N/A	N/A	N/A

Table 4: Summary of Capital, O&M and Levelized Costs for EPA Estimate Method, 2022 Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
PM-10 Control Alternative (Ranked by PM-10 Rate)	**PM Removal Efficiency %** (Note B)	Emissions				Economic Impacts			
		Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	54.55	0.010	152	566	679	406.1	29.8	78.0	114,900
Upstream FF	54.55	0.010	152	566	679	338.3	29.9	70.1	103,200
Wet ESP	54.55	0.010	152	566	679	622.2	16.6	90.4	133,100
Reheat ESP	54.55	0.010	152	566	679	220.2	10.5	36.6	53,900
Reheat FF	54.55	0.010	152	566	679	293.4	14.9	49.7	73,200
2022 Baseline (Scrubber)		0.022	334	1245		N/A	N/A	N/A	N/A

Table 5: Summary of Capital, O&M and Levelized Costs for EPA Estimate Method, EPA Emission Baseline

Summary of Particulate Emissions Control Costs from Colstrip									
PM-10 Control Alternative (Ranked by PM-10 Rate)	PM Removal Efficiency % (Note B)	Emissions				Economic Impacts			
		Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost in millions $	Annual O & M Cost in millions $	Total Annual Cost millions/yr	Average Control Cost $/ton
Upstream ESP	48.72	0.010	152	566	538	406.1	29.8	78.0	145,000
Upstream FF	48.72	0.010	152	566	538	338.3	29.9	70.1	130,300
Wet ESP	48.72	0.010	152	566	538	622.2	16.6	90.4	168,000
Reheat ESP	48.72	0.010	152	566	538	220.2	10.5	36.6	68,000
Reheat FF	48.72	0.010	152	566	538	293.4	14.9	49.7	92,400
2022 Baseline (Scrubber)		0.0195	296	1103		N/A	N/A	N/A	N/A

We appreciate the opportunity to assist in this evaluation. Should you have any questions or wish to schedule a follow-up meeting, please contact Doug Randall at (816) 822-3455.

Sincerely,

Burns & McDonnell Engineering Company, Inc.

Douglas Randall
Associate Controls Specialist

June 23, 2023

Via Federal eRulemaking Portal [regulations.gov]
Via Email [benish.sarah@epa.gov]

Ms. Sarah Benish
Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Re: NorthWestern Corporation Comments re: Proposal on National Emissions Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

Docket ID No. EPA–HQ–OAR–2018–0794

Dear Ms. Benish:

On behalf of NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern"), I am commenting on the U.S. Environmental Protection Agency's ("EPA's") proposed changes to the National Emissions Standard for Hazardous Air Pollutants ("NESHAP") for the Coal- and Oil-fired Electric Utility Steam Electric Generating Units ("EGUs"), commonly known as the Mercury and Air Toxics Standard ("MATS"). The proposed changes were published in the *Federal Register* on April 24, 2023, at 88 Fed. Reg. 24,854 ("Proposed Rule"). As discussed herein, the Proposed Rule poses significant challenges for NorthWestern and its rate-paying customers in Montana, will likely have environmental and Environmental Justice impacts that are contrary to Administration policies, and is likely unlawful.

NorthWestern agrees with and incorporates by reference the concurrent comments submitted by Talen Montana, LLC ("Talen") as part owner and based on its knowledge as operator of Units 3 and 4 of the Colstrip Steam Electric Station ("Colstrip"). NorthWestern. NorthWestern endeavors to minimize duplication of the Talen comments.

These comments are organized into the following sections:

- Summary of Comments;
- NorthWestern's commitment to environmental and climate responsibility;
- NorthWestern's commitment to Environmental Justice;
- NorthWestern's energy portfolio and role in serving Montana electricity customers;

- Transmission limitations on the ability to import power;
- Inability to close Colstrip prior to 2035 without constructing replacement thermal baseload capacity;
- Costs of installing additional controls on Colstrip;
- Colstrip and NorthWestern portfolio scenarios;
- Cost and safety hazards of closing Colstrip prior to 2036 without constructing replacement thermal baseload capacity;
- Consequences of diverting capital from other beneficial projects to comply with the Proposed Rule
- Prejudice to NorthWestern of the Proposed Rule;
- Statutory and Administrative Procedure Act deficiencies with the Proposed Rule; and,
- Requests.

Each of these subjects is addressed below.

1. ***Summary of Comments***

The Proposed Rule, if finalized in its current form, is deeply harmful to the residents of Montana and will work in contradiction to the President's environmental objectives in Executive Order 13990, and Executive Order 12898, as most recently amended by the President on April 23, 2023. This is a result of the specific history and current electrical generation and grid limitations of NorthWestern and Montana.

As EPA is aware, Colstrip is in full compliance with the current MATS standards, which EPA does not dispute meet the statutory objectives of the Clean Air Act. However, as EPA also acknowledges and Talen explains in detail, Colstrip cannot come into compliance with either of the candidate standards set forth the Proposed Rule without extensive supplementation of existing pollution controls – the venturi wet scrubbers currently in use cannot meet the proposed standards. As detailed by Talen, upgrading Colstrip to comply with the Proposed Rule is cost-prohibitive, resulting in at least $350,000,000 in capital costs, plus an additional $15 million annual operating costs. *See* Talen Comments, Attachment C. NorthWestern and residents of Montana would bear the majority of these costs. Colstrip is the only facility identified by EPA as facing this predicament.

In addition, if Colstrip is closed in the near term, NorthWestern cannot provide adequate and reliable electrical service for its Montana customers without new replacement baseload capacity. Colstrip currently plays an essential role in baseload capacity for NorthWestern, and there are no near-term feasible means to replace Colstrip's capacity with other existing NorthWestern capacity or market purchases from in-state or out-of-state sources. Imported power is further constrained by significant transmission limitations.

NorthWestern has modeled and evaluated scenarios for closure of Colstrip in 2025, 2030, and 2035, and 2042 in its May 2023 Integrated Resource Plan. The 2025 and 2030 closure scenarios expose NorthWestern to extreme degrees of market risk, resulting high probabilities of ruinous market electricity purchases and grid instability.

If the Proposed Rule is finalized in its current form, NorthWestern will therefore be faced with an array of costly and environmentally unsound choices. Renewables are not a viable option because NorthWestern's portfolio is already renewable-heavy, and additional renewable capacity will not solve the problem of variable generation deficits NorthWestern currently experiences.

On the one hand, if NorthWestern participates in upgrades to Colstrip, it will either need to materially increase electricity rates for Montana customers, or redirect funding previously earmarked for other projects. Projects that may be abandoned to fund Colstrip upgrades include transmission improvements, planned upgrades to facilities that are in excess of maintenance requirements, or other non-required beneficial capital projects. The vast majority of these have direct environmental benefits, deferral of which would undermine or even fully negate the environmental benefits of the Proposed Rule.

Alternatively, the only baseload capacity that can conceivably be constructed within the statutory compliance deadlines is new natural gas generation capacity. Carbon-free baseload alternatives are either unproven, or require significantly longer development times. The net result would be a substantial investment in a new, large, long-lived fossil fuel based generation assets. This outcome would clearly contradict the objectives of E.O. 13990.

NorthWestern has been substantially and uniquely prejudiced by EPA's course of action. The 2020 Residual Risk Technology Review ("RTR") confirmed that Colstrip's pollution controls satisfy the requirements of the Clean Air Act, and there have been no significant technological or implementation advancements since the 2020 RTR that would change that conclusion. Had NorthWestern known that EPA would undertake a complete reversal of the conclusions of the 2020 RTR just three years later, NorthWestern could have factored compliance costs earlier and more robustly into NorthWestern's Integrated Resource Planning process.

The combination of prejudice to NorthWestern and the ratepayers of Montana, coupled with mis-application of the technology review provisions of Clean Air Act Section 112(d)(6), places EPA at significant risk of having the Proposed Rule declared as arbitrary and capricious and contrary to law.

Consequently, NorthWestern respectfully urges EPA to use its discretion under the Clean Air Act and E.O.s 13990 and 12898 to take the following actions:

(1). Withdraw the Proposed Rule, revisiting the subject closer to the eight year timeframe provided in Clean Air Act Section 112(d)(6), or earlier if and when actual technological advancements occurring since the 2020 RTR satisfy the conditions for revisitation of standards set forth in Section 112(d)(6);

(2). If the Proposed Rule is not withdrawn, create a source subcategory that exempts those facilities presently employing wet scrubber technology without ESP or fabric filter add-ons until the next RTR; and/or

(3). Create a retirement subcategory allowing units to continue to meet the existing 0.03 lb/MMBtu fPM standard so long as they opt-in to the retirement subcategory within 18 months after finalization of the rule, with a retirement date no later than December 31, 2035 (and where continued operation after 2035 would later be permitted if (i) the unit is essential to maintain regional grid reliability, as determined by the Western Regional Adequacy Program, Regional Transmission Organizations, Independent System Operators, North American Electric Reliability Corporation, or other similar system reliability authorities; or (ii) or if EPA determines that additional time is required to allow the unit to transition to renewable or clean energy generation).

The foregoing courses of action are the only options that comply with the statutory requirements of the Clean Air and Administrative Procedure Acts, and are consistent with the objectives of E.O.s 13990 and 12898.

2. <u>NorthWestern's commitment to environmental and climate responsibility</u>

NorthWestern is a strong proponent of environmental protection, consistent with its responsibilities to deliver reliable, cost-efficient electrical service to its customers. To that end, NorthWestern has a corporate objective to achieve net zero emissions by 2050 ("Net Zero 2050"). A copy is attached as Exhibit A. NorthWestern already has one of the highest percentages of carbon-free generation in the United States, and has significant additional carbon and other emissions-reducing projects in development. Although NorthWestern disagrees strongly with the Proposed Rule, this should not be confused with opposition to environmental protection or the objectives of E.O. 13990.

3.　NorthWestern's commitment to Environmental Justice

NorthWestern shares the Administration's commitment to Environmental Justice. NorthWestern has extensive programs to support critically needed affordable and reliable energy to low income and tribal communities within NorthWestern's service area. It is not clear from the Proposed Rule and supporting documentation that EPA has fully considered the Environmental Justice consequences of the Proposed Rule, especially as related to Montana and the Environmental Justice communities in Montana. For example, 25% of NorthWestern's service base is low income, with approximately half of those below poverty standards. The costs of the Proposed Rule will fall in important ways on those who are least able to afford it, and as detailed further in Sections 4 and 5, the grid reliability dangers posed by Proposed Rule also threaten the most vulnerable in Montana. In addition to the essential services NorthWestern provides, Colstrip and the Rosebud Mine supplying Colstrip directly employ 82 people of tribal affiliation, or 14% of the facilities' total employment. Premature closure of Colstrip would devastate these families and the Colstrip community as a whole.

Consistent with the Administration's updates and revisions to Executive Order 12898 (Executive Order on Revitalizing Our Nation's Commitment to Environmental Justice, April 21, 2023), EPA must evaluate these Environmental Justice effects in comparison with the claimed health benefits of the Proposed Rule. This is an acute issue where the environmental benefits claimed from the rule are extremely incremental (from 99.6% fPM existing removal efficiency to 99.8% efficiency under the Proposed Rule), and start from a baseline level of performance that is highly protective of human health and in compliance with Clean Air Act objectives.

4.　NorthWestern's energy portfolio and role in serving Montana electricity customers

NorthWestern provides energy and capacity to customers in Montana, South Dakota, and Nebraska. For transmission interconnection reasons explained later, Colstrip is principally relevant and important to electrical supply in Montana. NorthWestern provides electricity to customers in its service areas in Montana and also serves as a "Balancing Authority," which means that NorthWestern is responsible for ensuring that the supply of and demand for electricity within our Balancing Authority Area are in equilibrium or balanced.

The Montana Public Service Commission ("MPSC") oversees NorthWestern's resource planning activities and the recovery of costs of generation and power purchase agreements. At all times relevant to this matter, the MPSC had set forth the following objectives that Montana utilities should meet: (a) reliability; (b) affordability; (c) environmental responsibility; (d) optimality; and (e) transparency. *See* MCA 69-3-1202.

NorthWestern thus has legal obligations to reliably and affordably supply electricity to its customers in Montana and to do so cost-effectively while seeking to reduce adverse environmental impacts. In addition to those legal obligations, NorthWestern recognizes that as a practical matter its customers count on NorthWestern to provide the cost effective electricity used to power their homes and businesses and the critical infrastructure upon which they rely.

Under Montana law, NorthWestern, as a regulated public utility, is required to prepare and file a plan every 3 years for meeting the requirements of its customers in the most cost-effective manner consistent with its obligation to serve under the law. MCA § 69-3-1204(1)(a).

The plan must include:

a. an evaluation of the full range of cost-effective means for the public utility to meet the service requirements of its Montana customers, including conservation or similar improvements in the efficiency by which services are used and including demand-side management programs in accordance with 69-3-1209;
b. an annual electric demand and energy forecast developed pursuant to commission rules that includes energy and demand forecasts for each year within the planning period and historical data, as required by commission rule;
c. assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to commission rules;
d. an assessment of the need for additional resources and the utility's plan for acquiring resources;
e. the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process in accordance with 69-3-1207; and
f. descriptions of at least two alternate scenarios that can be used to represent the costs and benefits from increasing amounts of renewable energy resources and demand-side management programs, based on rules developed by the commission.

Planning for reliable service requires NorthWestern to ensure that it has enough electricity generation resources to meet its customer demands every hour of the year, even with changing weather and demands. As a matter of physics, for the electric grid to operate reliably, the amount of energy generated (“generation”) and the consumption of that energy (“load”) must be equal or in balance. Generation and load must be in balance year-to-year, month-to-month, day-to-day, hour-by-hour, and minute-by minute for the electric grid to remain stable. Because of the long lead times needed to build or acquire new electrical generation or transmission assets or negotiate power purchase contracts, NorthWestern, like other electric utilities, makes plans for the supply of electricity years in advance. This long-term planning is also required by law. In Montana, NorthWestern prepares formal, written plans that are filed with the MPSC. Attached as Exhibits B-1 and B-2 to these comments is a copy of Volume 1 of NorthWestern's 2019 Electricity Resource Procurement Plan ("ERPP"), which was filed at the MPSC in Docket No. N2018.11.78.[1] Attached as Exhibit C is the 2020 Supplement to the 2019 Plan. Attached as Exhibits D and E are the two volumes of NorthWestern's May 2023 Integrated Resource Plan ("2023 IRP").

NorthWestern began to serve customers in Montana when it purchased the transmission and distribution assets of the Montana Power Company in 2002. Initially, NorthWestern did not own any generation assets to serve Montana customers. This situation was not ideal as it required NorthWestern to purchase all the electricity needed to serve customers. These purchases were and continue to be from a market that experiences volatile pricing and increasing supply shortages.

Since then, NorthWestern has acquired various types of electricity supply resources. Most notably, in 2014 NorthWestern purchased a portfolio of hydroelectric facilities in Montana. NorthWestern has also made significant investments in wind power. NorthWestern currently owns approximately 1,271 megawatts ("MW") of generation capacity and has long-term contracts for another 680 MWs.

NorthWestern's generation portfolio now is a diverse mix of resources, the majority of which are renewable. The portfolio includes 497-MW of hydroelectric maximum delivered capacity, 455-MW of maximum delivered wind capacity, 222-MW of coal capacity, 202-MW of natural gas capacity, 87-MW of waste coal capacity, and 187-MW of solar capacity. The Company also has market capacity contracts for 460 MWs which have price or market exposure. In summary, NorthWestern's current portfolio has 202 MW of natural gas capacity, 309 MW of coal and waste coal based capacity, and 1,129 MW of renewable fueled generation.

The table below lists NorthWestern's existing owned generation facilities and contracted generation resources along with some additional resources that the Company expects to bring online, including the Yellowstone County Generating Station, which is currently under construction.

[1] Volume 2, which includes underlying hourly data among other material, is so voluminous that NorthWestern usually only provides it in electronic form. Given the size of Volume 2 and the number of additional files that would require submission, it is not provided with these comments. NorthWestern will certainly provide it if desired or needed for EPA's evaluation.

MT Portfolio Resources
Hydro Generation – Online
Thompson Falls
Cochrane
Ryan
Rainbow
Holter
Morony
Black Eagle
Hauser
Mystic
Madison
Turnbull Hydro LLC
State of MT DNRC (Broadwater Dam)
Tiber Montana LLC
+ QF Hydro Resources
Thermal/Natural Gas Generation – Online
Basin Creek
DGGS 1 -3
Thermal/Natural Gas Generation – Contracted
Yellowstone County Generating Station (Laurel)
Thermal/Coal Generation – Online
Colstrip 30% U4
Yellowstone Energy Limited Partnership (BGI) (QF)
Colstrip Energy Limited Partnership (QF)
Wind Generation – Online
Judith Gap Energy LLC
Spion Kop Wind
Two Dot Wind Farm
+QF Wind Resources
Solar Generation – Online
+QF Solar Resources
Solar Generation – Contacted
Clenera Apex I (QF)
Short Term Contracts – Max
Morgan Stanley (3 yr) On Peak Only, Q1, Q3, Q4 - expires 10/31/2023
Morgan Stanley (3 yr) ATC, Q1, Q3, Q4 - expires 10/31/2023
Powerex (3 yr) Contingency Reserves - expires 12/31/2023
Powerex (5 yr) - expires 12/31/2027
Heartland (10 yr) - (150 MW to 200 MW) - expires 12/31/2031

NorthWestern currently has over 200 percent more wind generation than its Colstrip generation. In terms of generation asset nameplate capacity, the two largest, by far, are hydroelectric assets and the fleet of wind farms, both of which are carbon free. NorthWestern's portfolio of solar generating facilities has also been increasing in recent years. At the same time, it is important to note the difference between "nameplate" and "accredited" capacity. Nameplate capacity refers to the maximum electrical generating output (in MW) that a generator can sustain over a specified period of time when not restricted by seasonal or other "deratings" (events that reduce effective output), as measured in accordance with the United States Department of Energy standards. In contrast, accredited capacity means the electrical rating given to generating equipment that meets the Utility's criteria for uniform rating of equipment. These criteria include but are not limited to reliability, availability, type of equipment and the degree of coordination between the Distributed Generation and the Utility. Wind and solar accredited capacities are much lower than their nameplate capacities, because of the seasonal and weather variability of those generation sources. Hydroelectric generation also has a gap between nameplate and accredited capacity, reflecting periods when generation is restricted by stream flows. All this is reflected in the table below:

MT Portfolio Resource	Nameplate Capacity (MW)	Accredited Capacity (MW)
Hydro Generation - Online		
Total	497	298
Thermal/Natural Gas Generation - Online		
Total	255	195
Thermal/Coal Generation - Online		
Total	309	288
Wind Generation - Online		
Total	455	59
Solar Generation - Online		
Total	97	1
Short Term Contracts - Max		
	460	460
Total	**2073**	**1301**

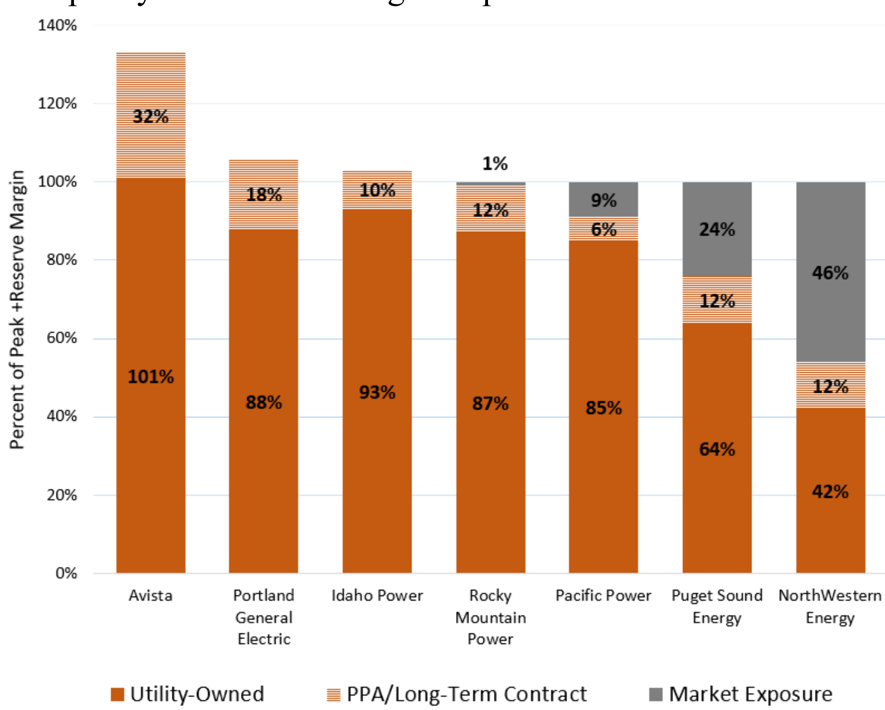
In fact, while news coverage of NorthWestern often discusses the coal or natural gas facilities, the proportion of NorthWestern's generation resources that are renewable compares highly favorable to other utilities. In 2022, 59% of NorthWestern's electric generation was from carbon-free resources, which compares to 40% of megawatt hours generated by the U.S. electric power industry as a whole.

Despite the significant improvement in NorthWestern's generation capacity, including acquisitions of hydroelectric plants and wind farms, NorthWestern's resource portfolio is not yet sufficient or "reliable", as defined by regional planning organizations.

In periods of peak loads, NorthWestern often does not have sufficient capacity, meaning that NorthWestern must make market purchases of electricity to meet customers' needs.

Periods of peak load are those times when customer demand for electricity is particularly high. This tends to occur during periods of extreme weather, during the coldest winter days (below 10 degrees Fahrenheit) when more electricity is used for heating purposes and during the hottest summer days (above 90 degrees Fahrenheit) when more electricity is used for cooling. The availability or unavailability of other resources can also be a significant factor. For example, the amount of rain during a season or snow during a preceding winter impacts the generation of our hydroelectric facilities. Similarly, there are periods when more or less wind power is generated. Unfortunately, critical weather in Montana typically occurs with high pressure, meaning wind generation more frequently than not generates very little power during these critical conditions. Those instances when there is both high demand for electricity and less available renewable generation can be particularly challenging from both a reliability and customer affordability perspective.

The chart below, which is drawn from NorthWestern's 2019 Electricity Supply Resource Procurement Plan filed at the MPSC, illustrates the difference between NorthWestern's available capacity and that of its regional peers.



As the chart shows, NorthWestern relies more heavily on market purchases to meet its electric needs during peak periods than any other utility in the Pacific Northwest. There are significant disadvantages to being reliant on market purchases to manage peak demand periods.

As an initial matter, prices for electricity tend to increase when there is greater demand. Typically, NorthWestern's periods of peak demand coincide with those of other utilities in the region. At the same time market prices are increasing during the critical weather events, especially winter, the available wind and solar generation frequently diminishes, sometimes to near zero. The same weather patterns that impact Montana also frequently impact other states in the region. As a result, the demand for electricity is high during such periods, which drives up the prices. Those higher prices increase our costs and ultimately lead to higher bills for our customers, which impacts their household and business finances and the broader Montana economy. Importantly the costs of electricity obtained through power purchase contracts are substantially passed directly through to consumers. NorthWestern's lower income and smaller business customers tend to be most sensitive to the impacts of increased electric costs.

In addition to pricing, there is also the question of availability. Simply put, it is not prudent to assume that there will always be sufficient out-of-state power that can be both purchased and transmitted to Montana. The limitations of the transmission system and how those impact NorthWestern's ability to bring electricity into Montana to serve customers are discussed in more detail in Section 5. This section further discusses the availability of electricity to purchase, setting aside the increasing uncertainty of whether it can be transmitted to Montana.

In recent years, several large power plants in Montana and adjacent states have closed. J.E. Corette, with a nameplate capacity of 163 megawatts (MWs), was closed in 2015. Colstrip Units 1 and 2, each with nameplate capacities of 307 MWs, ceased operation in early 2020. That same year, the Boardman plant in Oregon, 601 MWs, and Unit 1 of the Centralia plant in Washington, 730 MWs, both closed. Idaho Power ended its participation in Unit 1 of the Valmy facility, 254 MWs, in 2019 and the operations there completely halted in 2021.

In addition to those significant retirements that have already taken place, more retirements are anticipated in the near future. In particular, Unit 2 of the Centralia plant, 670 MWs, is scheduled to cease operation in 2025, as is North Valmy Unit 2, which is 289 MWs.

In summary, there is much less reliable electrical generation available in Montana and the Pacific Northwest (the market) than in the past, and the closures scheduled for 2025 are expected to result in the loss of an additional 959 MWs of nameplate capacity by the end of that year. Importantly, these losses of nameplate capacity are all for facilities for which their accredited capacity is very close to their nameplate capacity. As a result, the regional portfolio is shifting away from high-accredited to low-accredited generation sources. A difficult situation is expected to get worse and grave reliability concerns are no longer just the province of states like California and Texas that have had well publicized blackouts.

Equally importantly in terms of timing and supply, 185 MW of NorthWestern's current market contract capacity will be expiring by mid-2024. Given the retirements of facilities throughout the region, NorthWestern does not have confidence it will be able to renew or replace these contracts when they expire, especially under as favorable of terms. To the extent any can be replaced, market conditions indicate that they will be at much higher costs, which will be passed directly on to customers.

Montana's decision to deregulate its electricity sector, and the concurrent decision by Montana Power Company to sell all of its electricity generation portfolio, coupled with subsequent plant closures, has placed NorthWestern in a critically tenuous position of not being able to reliably serve its customers' needs during periods of peak loads, such as hot summer and most critically, cold winter days. This is in spite of NorthWestern acquiring a substantial amount of generation since 2011, none of which has been carbon-emitting. In NorthWestern's 2017 and 2019 Electricity Supply Resource Plan (and in the 2020 supplement), NorthWestern identified significant deficiencies and risks to customers due to our portfolio's reliance on market purchases, much of which originates from out of state, plus a lack of reserve margin to reliably serve our customers. These Plans empirically and analytically set forth particular capacity vulnerabilities that need to be addressed in order to continue to provide reliable service to our customers. In particular, NorthWestern identified a need to have resources available to serve 20-hour, 10-hour, and 5-hour periods in the future when there will be capacity portfolio deficits.

Notably, NorthWestern at that time did <u>not</u> identify a need for new baseload capacity. As stated in the 2019 ERPP, "NorthWestern's resource portfolio generally generates enough energy to serve average load, but is significantly short both peaking and flexible capacity." A key reason that NorthWestern did not plan for new baseload capacity was that it had made substantial investments in Colstrip to comply with the 2012 MATS Rule and regional haze requirements. NorthWestern knew that Colstrip would be able to achieve Clean Air Act statutory and health-based standards over the medium-to-long term. NorthWestern had contemporaneous public assurances from EPA to that effect. And NorthWestern knew that there were no significant pollution control technology advancements in the offing that would change control performance. Consequently, the 2019 ERPP and 2020 Supplement focused investment on the identified peaking and flexible capacity needs, as well as improving transmission capabilities.

Based on those identified needs, NorthWestern issued a Request for Proposals (RFP) in January 2020. This RFP was explicitly for any type of generation that was able to provide capacity for those three distinct shorter-duration categories. This RFP was conducted by an independent and respected third party. NorthWestern was not directly involved in the evaluation process. After receiving the identified short-list from the evaluator, NorthWestern in conjunction with the evaluator selected three proposals: the Yellowstone Generating Station to address the 20-hour need and a portion of the 10-hour capacity need, a 5-year power purchase agreement with Powerex Corp., the marketing partner of BC Hydro System, to address the remaining portion of the 10-hour duration need and part of the 5-hour need, and a contract with Beartooth Energy Storage, LLC for a 50 MW, 4-hour battery facility to be located near Billings for the remaining portion of the 5-hour duration need. No RFP was issued to upgrade or replace Colstrip capacity, because no need had been identified.

5. __Transmission limitations on the ability to import power__

The United States electric grid has an Eastern Interconnection, a Western Interconnection, and a separate Texas interconnection, which each operate largely independently with limited transfers of power between them. NorthWestern's Montana electric transmission system is located in the Western Interconnection of the United States grid. NorthWestern also has an electric transmission system in South Dakota; however, that is in the Eastern Interconnection and there is no effective means to transfer electricity from NorthWestern's South Dakota generation sources to Montana. In addition, those generation sources are fully subscribed.

NorthWestern manages its transmission system in Montana as a Balancing Authority Area ("BAA") operator, with responsibility for ensuring that system supply and demand are in constant balance. To support the continuous flow of electricity, NorthWestern is also responsible to provide ancillary services such as scheduling, system control, and dispatch; regulation and frequency response; and contingency reserves. When demand and supply are not in balance, equipment damages, cascading outages, or blackouts can result. As a BAA operator, NorthWestern must meet and operate within the reliability standards established by NERC.

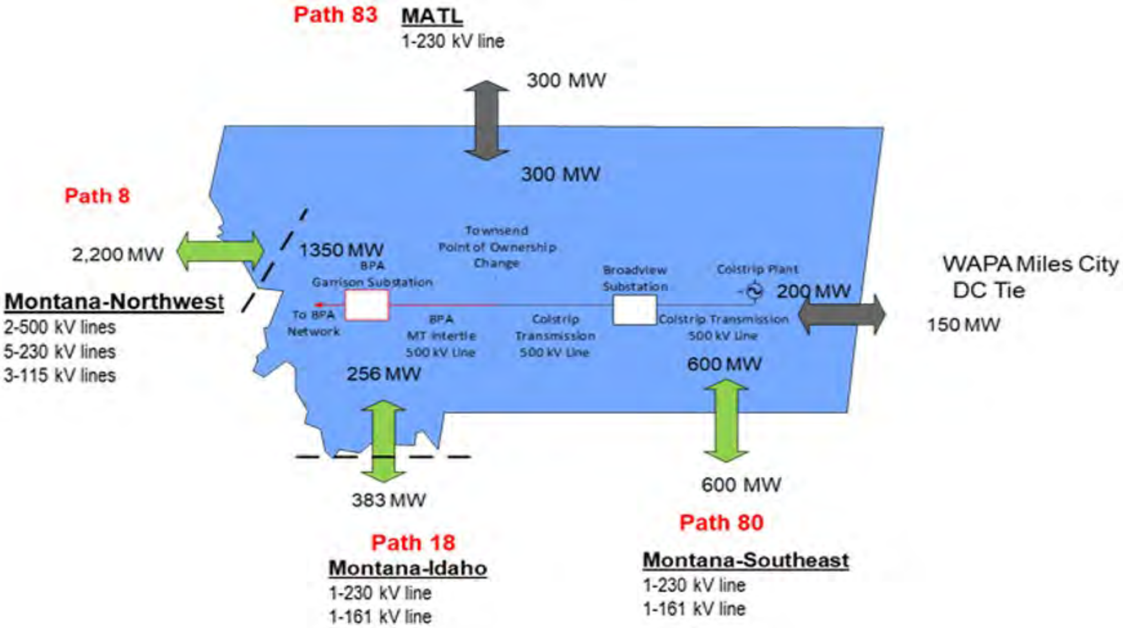
NorthWestern's Montana electric transmission system covers over 97,000 square miles. This integrated system includes about 7,000 miles of transmission lines. The system includes over 280 circuit segments, 79 transmission or transmission/distribution substations, and over 100,000 poles and towers. The transmission system integrates resources and loads through 500 kilovolt (kV), 230 kV, 161 kV, 115 kV, 100 kV, 69 kV, and 50 kV lines to deliver power to the various load centers dispersed throughout NorthWestern's service territory.

Montana was traditionally an exporter of power. However, following the 2015 closure of the J.E. Corette plant (163 MW) and the 2020 closure of Colstrip units 1 and 2 (614 MW), the NorthWestern BAA has transitioned from being a net exporter of energy to a net importer. During the most critical periods, times of peak energy demand, NorthWestern now relies heavily on imports, and frequently on non-firm transmission, to meet customer needs. "Firm" transmission is transmission capacity reserved for the full duration of the transmission service agreement. In contrast, "non-firm" is transmission capacity that can be used only on an as-available basis when unreserved capacity is available on the transmission system. The existing NorthWestern transmission system was not designed to transmit imports, serving such a large portion of customer load.

NorthWestern's transmission system and its connections to utilities in other states were not designed to import significant additional amounts of electricity. While there are existing lines and interconnections, there is limited capacity available on those facilities and further complications and congestion outside of Montana, making it imprudent for NorthWestern to assume it can import additional power when needed. Redundancy in the reliable transmission of energy is also extremely important because an outage on one transmission line can cause overloads to another. Relying on transmission lines and interconnections to import the electricity needed to serve such a large portion of our Montana load inherently increases the risk of outages and the resulting failure to serve customers during times of greatest electricity demand.

NorthWestern's transmission system has interconnections to six major transmission utilities – Idaho Power Company, Avista Corporation ("Avista"), BPA, Western Area Power Administration ("WAPA"), PacifiCorp, and the Alberta Electric System Operator as noted in Figure 1 below. NorthWestern transfers power in and out of Montana through Western Electricity Coordinating Council ("WECC") rated "Paths", each consisting of transmission lines crossing Montana's borders. To the west and south are Paths 8, 18, and 80, and to the north is Path 83, on the Montana Alberta Tie Line ("MATL"), and these are shown in the figure below. Note MATL is not owned or operated by NorthWestern. Figure 1 shows the Total Transmission Capability amounts, or TTCs. However, TTC represents the total designed and approved transmission capacity, not the amount of additional available capacity above the capacity already in use.

Figure 1: WECC Paths and Total Transfer Capability (TTC in MW)



As can be seen, the largest single path to the Pacific Northwest and other Western Interconnection markets is Path 8, which consists of the interconnections with BPA and Avista. As the figure indicates, Path 8 is made up of multiple lines and has a significantly higher TTC than the other paths.

However, there is very little Available Transmission Capacity ("ATC"), which is the difference between the TTC and the amount of capacity already reserved by existing transmission commitments, that could be used to import additional electricity to NorthWestern's system via Path 8 for the foreseeable future. In short, Path 8 is a significant and convenient interstate transmission path, but its capacity has already largely been reserved.

Path 80, located in the southeastern portion of Montana, theoretically has more ATC. However, it is a very complex path that experiences significant congestion and curtailments due to reliability issues. Path 80 is greatly impacted by what is going on in other transmission owners' transmission systems outside of Montana. Path 80 is affected by loads and generation in Wyoming, Colorado, and Utah as well as other potential impacts. Moreover, Path 80 is far from the Pacific Northwest market, causing greater potential congestion if it is used to import power from that area. As one example of the problems with Path 80, during the significant cold weather of February 2021, there were curtailments of transmission on Path 80 at the worst possible time. Path 80 very commonly has non-firm transmission curtailed (and sometimes even firm transmission) as a result of congestion on the transmission system in Wyoming and further south. This most commonly happens during peak events, but also during non-peak events. That is the reason NorthWestern currently has no remaining firm import ATC posted on Path 80.

Path 83 provides transmission capacity between Montana and Canada. Path 83 consists of a single 230 kV line – the Montana Alberta Tie Line, which is not owned by NorthWestern. Most of the activity on the Path is related to wind projects located in north central Montana, also not owned or controlled by NorthWestern. Additionally, Path 83 is a very complex path that routinely must be curtailed to manage generation and loads. This path also contributes significantly to our challenges and limitations across an internal path we refer to as "South of Great Falls". The South of Great Falls path frequently must be curtailed and has impacts on the Great Falls, Billings, Helena and Butte areas.

Path 18 has relatively smaller overall capacity and is highly utilized today with little import capacity remaining. As described in Paragraph 23 below, for several years ending in 2012 NorthWestern attempted to permit an upgrade to the transmission capacity of Path 18 through the proposed Mountain States Transmission Intertie ("MSTI"). Ultimately, that effort failed. Consequently, Path 18 offers little potential for increased imports at this time.

In summary, ATC is quite limited for import into the NorthWestern BAA. Figure 2 below is a snapshot as of February 23, 2023 of long-term firm ATC that is posted on NorthWestern's Open Access Same-time Information System ("OASIS") for each year displayed. The OASIS provides real-time, up-to-date information and access to transmission system capacity for all customers. Figure 2 clearly indicates that there is very little to zero firm ATC to import from any Path of import.

Figure 2: Import Available Transfer Capability (ATC in MW)

Yearly Firm ATC by Year (as of 2/23/2023)		
	BPA Import	Yearly Firm ATC
Path 8	2023	0
	2024	31
	2025	47
	AVAT Import	
	2023	196
	2024	162
	2025	162
Path 18	*BRDY Import*	
	2023	59
	2024	59
	2025	0
	Jeff Import	
	2023	72
	2024	72
	2025	72
Path 80	*YTP/Crossover Import*	
	2023	0
	2024	0
	2025	0

Even when there is available capacity on a path, NorthWestern has to compete with other transmission customers/users. The operation of NorthWestern's transmission system is subject to regulation by FERC in accordance with NorthWestern's FERC-jurisdictional Open Access Transmission Tariff ("OATT"). As a result, NorthWestern is required to provide transmission service to several types of customers on a first come first serve basis, which means that there is competition for ATC among many potential users of the transmission system. NorthWestern's transmission system serves four types of customers – retail, network, interconnection, and point to point ("PTP"). In addition to NorthWestern's retail customers, our FERC customers include electric cooperatives, federal marketing agencies (e.g. BPA and WAPA), and "choice" customers, who are all customers that do not receive their electric supply service from NorthWestern. This means that there are many non-NorthWestern entities within the NorthWestern BAA that are competing for available transmission, constraining transmission of power at critical peak times when customers need that power the most. Critically, this transmission competition is becoming much greater as in-state generation shuts down. As noted above, transmission capacity is awarded on a first-come, first-served basis. Of critical importance is that NorthWestern's own "native" load does not receive any preference over other eligible customers. In addition, there are rules governing what is a valid transmission service request or network service designation. For example, long-term network transmission service designation requests must be tied to legitimate network resources with valid contracts for service in place. Figure 3 displays the current firm transmission imports that are reserved on a long-term basis by parties. Many of these reservations are not for service to NorthWestern's customers. This transmission capacity is reserved under NorthWestern's FERC OATT, which includes point-to-point customer wheeling into and out of NorthWestern's system, and Network customers, including some reservations by NorthWestern, importing energy from outside of Montana and into NorthWestern's transmission system to serve load.

Figure 3: Long-term Firm Reservations by Customer Type

Long Term Firm Reservations from Import Interface Paths (as of 01/27/2023)				
	Path 8 Imports	Path 83 Imports	Path 80 Imports	
Network	690	225	37	
Point to Point	342	0	31	
Total	1032	225	68	1325

While NorthWestern faces challenges resulting from limited transmission capacity, it might seem the obvious solution would be to build new transmission lines. However, that is only a solution in theory; in reality, it is not currently a practical option. As an initial matter, increased transmission is only useful in addressing capacity constraints if it connects to a generation resource willing and able to sell capacity to NorthWestern, and as explained in Section 3, there is significant uncertainty on that point going forward given recent and planned power plant closures.

Even if an additional generation resource is located, attempting to build the transmission lines to that resource is a difficult, time-consuming, and expensive endeavor that might not succeed. NorthWestern would have to gain approval from the Montana Department of Environmental Quality ("DEQ") to permit, site, and construct new transmission infrastructure by obtaining a certificate of compliance under the Montana Major Facility Siting Act ("MFSA") and gain rights-of-way over the proposed transmission path. Securing easements across land owned privately or by state or federal agencies can be extremely challenging. Permitting approval would likely be required from other state or federal agencies as well. The transmission infrastructure would also have to be designed to satisfy regulatory requirements enforced by FERC, NERC, and WECC. The combination of all these factors means that actually obtaining authority to construct a transmission line would take several years, if it is achievable at all.

Increasing transmission capacity, if it could be accomplished, would require upgrades to not only NorthWestern's system, but potentially other transmission systems outside of Montana. Of course, work in other states would require satisfying the regulatory requirements in those jurisdictions. The need to cooperate with more than one utility and perform work in multiple jurisdictions makes transmission upgrades even more difficult as a solution.

As an example, in 2012, after spending four years and approximately $24 million, NorthWestern indefinitely postponed its attempts to secure permits for the proposed 500kV Mountain States Transmission Intertie ("MSTI"), which would have provided an additional connection outside of Montana. This transmission line would have extended from southwestern Montana to southcentral Idaho and would have been capable of transmitting approximately 1000 MW of power. The abandonment of the project was due to continued permitting issues including never-ending process, analysis and movement of goalposts, as well as difficulty in getting all agencies to timely act and cooperate to define a reasonable end to the permitting process. Although the Inflation Reduction Act has made available some resources for such projects, the regulatory environment in terms of approval timelines has not improved since 2012.

There are no presently proposed interstate transmission lines or upgrades that would facilitate added import capability into Montana. Given the MSTI experience, if a project was proposed tomorrow, it could require 7-10 years to design, permit, construct, and bring into operation, if that was even possible.

6. __Costs of installing additional controls on Colstrip__

The options and anticipated costs of installing additional controls on Colstrip to comply with the Proposed Rule are set forth in detail in Talen's comments, accompanied by a supporting analysis prepared by Burns & McDonnell. NorthWestern joins the Talen comments and will not reiterate them here. NorthWestern's comments assume capital costs of at least $350,000,000, and annualized costs of $57,000,000, based on the working assumption that Reheat Fabric Filter is the most viable technology Colstrip would deploy to comply with the Proposed Rule. ("Proposed Rule Costs").

7. __Colstrip and NorthWestern portfolio scenarios__

NorthWestern has not planned for the Proposed Rule or the Proposed Rule Costs. Because the Proposed Rule reflects a reversal or prior EPA analyses and conclusions, and is not based on new information, there was no reason for NorthWestern to anticipate the Proposed Rule or the Proposed Rule Costs in the 2019 ERPP or 2020 Supplement, and neither the Proposed Rule or the Proposed Rule Costs were factored into the recently completed 2023 IRP.[2]

As explained in Sections 4 and 5, Colstrip is central to NorthWestern's generation portfolio, and purchasing additional market capacity from existing generation sources to replace Colstrip's capacity carries high costs and risks from a generation resource or

[2] Although the 2023 IRP was released shortly after the publication of the Proposed Rule, the Proposed Rule was released far too close to the finalization of the 2023 IRP to be factored into the analyses and planning.

transmission perspective. Faced with hundreds of millions of dollars in unanticipated costs, NorthWestern therefore has three principal options: (a) close Colstrip in the immediate future and engage in an emergency program to construct additional baseload capacity; (b) install the controls required by the Proposed Rule and attempt to recoup the Proposed Rule Costs through rate increases; or (c) postpone or abandon existing planned capital projects to free up resources to address the unanticipated Proposed Rule Costs without raising rates. These scenarios are discussed in the following sections.

8. ***Cost and safety hazards of closing Colstrip prior to 2036 without constructing replacement thermal baseload capacity***

Although the Proposed Rule came as a surprise to NorthWestern, NorthWestern closely examined Colstrip closure scenarios as part of the 2023 IRP process. This included scenarios involving closures in 2025, 2030, and 2035. The 2025 and 2030 closure scenarios resulted in materially higher total costs, amounting to $1.1 billion in higher costs (25% increase over the base case) for a 2025 closure, and $540 million higher costs (12.1% increase over the base case) for a 2035 closure. *See* 2023 IRP, Exhibit B-1, Section 8.9. Moreover, these scenarios rely on substantial purchases of power at market rates, in excess of $50 million each year commencing with Colstrip's closure. *Id.* As explained in Sections 4 and 5, there is substantial uncertainty whether such large market purchases can even be consistently executed and delivered, especially during peak load events. Consequently, the 2025 and 2035 closure scenarios are accompanied by worrisome grid stability and service interruption hazards.

These risks are sufficiently high that NorthWestern would need to closely examine embarking on an emergency program to construct replacement thermal capacity. On the timeframes contemplated by the Proposed Rule, the only thermal capacity that could feasibly implemented is natural gas fired capacity. The net effect would be to replace relatively short-lived (approx. 10-20 year life) coal-fired thermal capacity with new, long-lived (30+ year) natural gas capacity. Although natural gas has a lower carbon and MATS profile than coal, this tradeoff would clearly appear to be inconsistent with the long term objectives of E.O. 13990.

9. ***Rate consequences of the Proposed Rule Costs and impracticality of rate recovery***

NorthWestern currently plans to invest over $2.4 billion in capital outlays over the next five years. Many of these investments are required by law. Others are intended to improve system reliability, better utilization of renewables, or other projects (e.g., wildfire mitigation) with demonstrable and significant environmental benefits.

Proposed Rule Costs would constitute significant increase in capital commitments, weighted toward the earlier part of the five years and could imperil NorthWestern's ability to make those critical investments.

Any rate increases to cover Proposed Rule Costs would be on top of other recent rate increases funding the existing capital and operational budgets. Presently pending before the MPSC is a 28% residential electricity rate settlement, driven in material part by NorthWestern's investments in carbon free and reduced-emissions projects. Proposed Rule Costs did not factor into the settlement. NorthWestern believes it is uncertain that the MPSC would approve cost recovery for such a large new increase on top of other recent increases, and may not approve any portion of it.

As a result, the most likely outcome of the Proposed Rule and Proposed Rule Costs would be to force NorthWestern to evaluate postponing or abandoning previously approved capital projects.

10. <u>Consequences of diverting capital to comply with the Proposed Rule</u>

As should be clear from the preceding discussion, it is unlikely that NorthWestern could feasibly comply with the Proposed Rule by either building replacement thermal capacity or by attempting to recoup the Proposed Rule Costs through rate increases, and early closure of Colstrip likely poses unacceptably high market and grid stability risks. This leaves a re-allocation of previously committed capital outlays as the most likely compliance scenario.

As discussed, a large fraction of the planned investments are focused on improving grid reliability, and upgrading existing renewables. Other projects (e.g. wildfire mitigation) have clear environmental benefits. NorthWestern had intended to perform a more detailed examination of potential capital program consequences of the Proposed Rule, had it been granted the requested extension of time to comment. Because that request was denied, NorthWestern can only hypothesize in more general terms.

The adverse net environmental consequences of capital reallocations from the subjects identified above should be obvious. The collective effect would be reduced utilization of renewables, slowing NorthWestern's progress toward its Net Zero 2050 objectives. Perversely, a very plausible scenario under the Proposed Rule, if implemented in its current form, would be to *extend* the life of Colstrip, and result in NorthWestern utilizing Colstrip *more heavily* than in the absence of the Proposed Rule. NorthWestern has not had the opportunity to fully calculate the emissions consequences, but there is a significant likelihood that, as applied to Colstrip, the Proposed Rule would have the effect of *increasing* net carbon and HAPS emissions over Colstrip's remaining life than if Colstrip is exempted from the Proposed Rule. Such a result would certainly be contrary to the objectives of E.O. 13990.

11. *Prejudice to NorthWestern of the Proposed Rule*

NorthWestern has been materially and uniquely prejudiced by the Proposed Rule. The 2023 RTR acknowledges that Colstrip will require far more extensive and expensive capital investments than any other facility subject to the Rule. RTR at 9. Indeed, the entire rationale for the Proposed Rule – that existing EGUs can attain additional emissions reductions at minimal cost – does not apply to Colstrip.

As revealed in the 2017 and 2019 ERPP's and 2020 ERPP supplement, NorthWestern did not plan for the Proposed Rule and Proposed Rule Costs, because it had no reason to anticipate them. As a result, NorthWestern made major capital commitments to improve integration of renewables, grid reliability, and transmission capacity. These all advance NorthWestern's progress toward Net Zero 2050. But these investments depended critically on the assumption that Colstrip would remain an essential component of NorthWestern's portfolio through approximately 2042, and that major new emissions controls to address mercury and HAPS would not be necessary given Colstrip's compliance with the performance objectives of the original MATS rule, the regional haze rule, and the statutory standards in the Clean Air Act. The Proposed Rule (as well as other regulatory initiatives detailed by Talen) would upend these assumptions.

NorthWestern also notes that the Proposed Rule, in combination with the other proposed rules, disincentivizes superior performance. As detailed by Talen, the venturi scrubbers control both sulfur dioxide and fPM. Colstrip has been a high performer in SO_2 emission reduction for years because of that system, but under the Proposed Rule Colstrip would be punished for having "wrong" system to control fPM, in comparison to other facilities.

No other utility bears anywhere close to the burden that NorthWestern would bear under the Proposed Rule. And, because Colstrip essentially serves only Montana, no other State would bear anywhere close to the burden that Montana electricity customers would bear.

12. *Statutory and Administrative Procedure Act deficiencies with the Proposed Rule*

The Proposed Rule is unlawful under Clean Air Act Section 112(d)(6). That Section provides that EPA must take into account "developments in practices, standards, and control technologies" in determining whether a revision in standards is necessary. EPA purports to satisfy this requirement by citing to performance data from 2017 to 2021, and opining that facilities have performed better and at lower costs than anticipated when the MATS Rule was promulgated in 2012. But this dataset is selective and misleading. All the performance and cost metrics EPA now relies on were known to EPA when it released the 2020 RTR. EPA has withdrawn its prior "Appropriate and Necessary" determination, but it has not withdrawn the 2020 RTR. As a result, the 2023 RTR is *not* based on "developments in practices, standards, and control technologies" since the prior

RTR, but rather only a *change in policy* regarding the *same* practices, standards, and control technologies.

Basing revised standards simply on a policy reversal is contrary to the text and structure of Section 112(d)(6), especially when coupled with the tight statutory compliance deadlines provided in Section 112. The Clean Air Act envisions that both EPA *and* the regulated community would be able to monitor evolving trends in emission control technologies and practices, such that regulated could see and plan for potential upgrades that might be needed on the horizon. But when EPA reverses course based on policy, not technological changes, regulated entities do not have similar advance notice when planning capital programs. This is contrary to the statute.

The Proposed Rule's statutory deficiencies are compounded by its proxy-on-proxy structure, where PM (a pollutant independently regulated under the NAAQS program) is used as a stand-in for HAPS. NorthWestern understands the technical rationale for focusing on PM rather than attempting to measure HAPS directly, but the indirectness of the regulation is problematic given the history of the Rule. Moreover, it will not be lost on a reviewing court that the Proposed Rule is a transparent attempt to indirectly regulate greenhouse gas emissions in the immediate wake of *West Virginia v. EPA,* 142 S.Ct. 2857 (2022). For that reason, and because of its severe impacts to Montana and the reliability of the Western Interconnection, there is a significant likelihood that a court will subject the Rule to scrutiny under the Major Questions Doctrine. It is doubtful that EPA's departures from the text and purposes of Section 112(d)(6) would survive such scrutiny.

Independently of statutory and constitutional infirmities, the Proposed Rule is also arbitrary and capricious under the Administrative Procedure Act. In addition to the reasons articulated by Talen, the Proposed Rule and 2023 RTR takes the same practices, standards, and control technologies as were examined in the 2020 RTR, and reaches a polar opposite conclusion. This is textbook arbitrariness. At a minimum, the fact that EPA has reversed course so completely in such a short timeframe likely deprives EPA of any judicial deference it might otherwise have enjoyed. Given the unprecedented methods deployed in the Proposed Rule to determine that the Rule would result in positive net benefits, there is a significant likelihood that the Proposed Rule, if finalized, would be invalidated under the APA.

13. Requests

As a result of the foregoing general deficiencies in the Proposed Rule and specific injuries to NorthWestern, NorthWestern respectfully requests the following actions. These are consistent with the concurrent requests by Talen.

(A). EPA should abandon the Proposed Rule until technological developments that warrant a new RTR have occurred

As explained above, the Proposed Rule is unlawful. As a result, and because of the significant prejudice and injury NorthWestern will suffer, EPA should withdraw the Proposed Rule until such time as a revised form of the Rule can be justified, if at all, by advancements in practices, processes, or control technologies, as envisioned by Section 112(d)(6).

(B). If rulemaking proceeds, EPA should create a subcategory exempting facilities with wet scrubbers only

In the event the Proposed Rule is finalized, at a minimum the Final Rule should create a subcategory for those facilities that employ wet scrubber control technologies without additional ESP or fabric filter controls, and exempt them from the Proposed Rule. The rationale of the Proposed Rule is that significant performance improvements can be obtained through minimal equipment upgrades and costs, and that is plainly not true of facilities that only employ wet scrubbers without additional controls. Therefore such facilities should be subject to subcategory treatment and exempted.

(C). If rulemaking proceeds, EPA should also create an opt-out option for facilities that decide, within one year of the publication of the Final Rule, to enforceably commit to closure by December 31, 2035.

If the Final Rule does not create an exempt subcategory for facilities with wet scrubbers alone, EPA should create a retirement subcategory allowing units to continue to meet the existing 0.03 lb/MMBtu fPM standard so long as they opt-in to the retirement subcategory within 18 months after finalization of the rule, with a retirement date no later than December 31, 2035 (and where continued operation after 2035 would later be permitted if (i) the unit is essential to maintain regional grid reliability, as determined by the Western Regional Adequacy Program, Regional Transmission Organizations, Independent System Operators, North American Electric Reliability Corporation, or other similar system reliability authorities; or (ii) or if EPA determines that additional time is required to allow the unit to transition to renewable or clean energy generation). This would provide units another compliance option and needed flexibility.

This timeline is also necessary in NorthWestern's case because of the prejudice NorthWestern has experienced in the development of the Proposed Rule, and the long-lead time needed for closure and planning and construction of replacement baseload capacity. Such a timeline will also maximize the likelihood that replacement capacity will be carbon-free rather than fossil fuel-based. In its deliberations, EPA must consider net environmental and environmental justice consequences over all time scales, rather than only short term objectives. This is both consistent with the law and the objectives of Executive Orders 12898 (as updated) and13990.

Conclusion

NorthWestern is disappointed that the Proposed Rule in its current form does not achieve its intended objectives, and that NorthWestern was deprived of the opportunity to submit additional useful information by EPA's denial of NorthWestern's extension request. Nevertheless, NorthWestern's strong carbon-free portfolio performance and Net Zero 2050 commitments demonstrate that it shares many of the Administration's long term environmental objectives. NorthWestern is available to further discuss the consequences of the Proposed Rule and potential solutions to the problems it poses. If you have any questions regarding these comments, or would like to further engage on the subject, please contact me at 406-443-7969 or shannon.heim@northwestern.com.

Sincerely,

Shannon M. Heim

Shannon M. Heim
Vice President and General Counsel
NorthWestern Energy

United States Environmental Protection Agency

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Review of the Residual Risk and Technology Review

Summary of Public Comments and Responses on Proposed Rule (88 FR 24854 April 24, 2023)

April 2024

FOREWORD

This document provides the Environmental Protection Agency's (EPA's) responses to public comments on the EPA's proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units - Review of the Residual Risk and Technology Review. The EPA published the proposal in the Federal Register on April 24, 2023, at 88 FR 24854 (2023 Proposal). A virtual public hearing was held on May 9, 2023. Public comments and the transcript for the public hearing are available electronically through https://www.regulations.gov by searching Docket ID No. EPA-HQ-OAR-2018-0794. Copies of all public comments and the transcript for the public hearing are also available at the EPA Docket Center Public Reading Room.

More than 120,000 public comments were collectively received on the proposed rule. The EPA Docket Center consolidated mass mail campaigns and petitions into single document control numbers, resulting in over 945 unique comments. Each of these comments was reviewed and all significant comments relevant to this action and submitted within the comment period have been summarized and included in this document. In some cases, comments with similar themes have been aggregated together. This document includes responses to the comments received on the proposed rule that are not addressed in the final rule preamble.

TABLE OF CONTENTS

ACRONYMS AND ABBREVIATIONS

While this list may not be exhaustive, to ease the reading of this document and for reference purposes, the EPA defines the following terms and acronyms here:

A&N	appropriate and necessary
APA	Adminstrative Procedure Act
Btu	British Thermal Units
CAA	Clean Air Act
CEMS	continuous emissions monitoring systems
CFR	Code of Federal Regulations
CO_2	carbon dioxide
CPMS	continuous parameter monitoring system
DOE	Department of Energy
DSI	dry sorbent injection
EBCR	Eastern Bituminous Coal Refuse
EGU	electric utility steam generating unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
FF	fabric filter
FGD	flue gas desulfurization
fPM	filterable particulate matter
GHG	greenhouse gas
HAP	hazardous air pollutant(s)
HCl	hydrogen chloride
HF	hydrogen fluoride
Hg	mercury
Hg^0	elemental Hg vapor
ICR	Information Collection Request
IGCC	integrated gasification combined cycle
IPM	Integrated Planning Model
IRIS	Integrated Risk Information System
lb	Pounds
LEE	low emitting EGU
MACT	maximum achievable control technology
MATS	Mercury and Air Toxics Standards
MMBtu	million British thermal units of heat input
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NEEDS	National Electric Energy Data System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	nitrogen oxides
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget

PDF	Portable Document Format
PM	particulate matter
$PM_{2.5}$	fine particulate matter
ppm	parts per million
QA	Quality Assurance
QC	Qualtiy Control
RCA	Relative Correlation Audit
RIA	Regulatory Impact Analysis
RRA	Relative Response Audit
RTR	residual risk and technology review
SC-CO_2	social cost of carbon
SCR	Selective Catalytic Reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SDA	spray dry adsorption
TBtu	trillion British thermal units of heat input
tpy	tons per year
WebFIRE	Web Factor Information Retrieval System

CHAPTER 1

1. The EPA's Authority

Comment 1: Commenters acknowledged that the EPA has the statutory authority to review and possibly revise MATS limits for Hg and non-Hg HAP but said the state agency opposed the process that the EPA has taken on the proposal. Commenters cited Clean Air Act (CAA) section 101(a)(3) finding that air pollution prevention and control are the primary responsibilities of States and local governments and said that the EPA should have worked cooperatively with the state agency to gather accurate information considering the state agency oversees more lignite-fired units than any other state agency. Commenters said the proposal was inconsistent with the EPA's Strategic Plan goal to foster state partnerships.

Response 1: Under section 112 of the CAA, the EPA has primary authority for setting standards for HAP. While the EPA is always interested in working with states and appreciates input from state commenters in the rulemaking process, the CAA is clear that establishing HAP standards is primarily the responsibility of EPA, which the EPA implements in coordination with state and local air permitting offices.

Comment 2: Commenters said the EPA's recission of the lignite subcategory does not comply with the APA because since 2005, the EPA has subcategorized EGUs based on the type of coal they combust as determined from facts in the administrative record. Commenters said the proposal effectively eliminates the lignite subcategory and said the proposal does not provide a "reasoned analysis" for doing so, as required by the APA. Commenters cited from the record, prior justifications for the "low rank virgin coal" subcategory and said that the EPA must provide its reasoning for the proposed decision to change their existing policy, citing *D.C. v. U.S. Dep't of Agric.*, 444 F. Supp. 3d 1, 6 (D.D.C. 2020). Commenters said the proposed rule and 2023 RTR takes the same practices, standards, and control technologies examined in the 2020 Final Action (85 FR 31286) and reaches a different determination, and commenters concluded that there is a significant likelihood that the proposal, if finalized, would be considered "arbitrary and capricious" and be invalidated under the APA.

Commenters cited *Ass'n of Battery Recyclers, Inc. v. E.P.A.*, 716 F.3d 667, 673 (D.C. Cir. 2013) and said that when determining if changes are "necessary" under CAA section 112(d)(6), the EPA is statutorily required to account for cost. Commenters said that courts have upheld the EPA' s past practice of further considering "feasibility, utility, cost-effectiveness, and adverse … environmental impacts …" when assessing whether to require additional limits under CAA section 112(d)(6). Commenters said that because the EPA has relied on such factors in the past, it would be unlawfully arbitrary for the EPA to fail to consider such factors without providing a rationale for the reversal in policy and cited *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009).

Response 2: The removal of the lignite subcategory complies with APA requirements. Contrary to some commenter's assertions, the EPA provided a "reasoned analysis" of the proposed change in the 2023 Proposal (88 FR 24875-82), which detailed the ability for lignite-fired units to meet Hg emission rates for other source categories. The EPA further disagrees with commenters that the EPA considered the same information as the 2020 Technology Review but arbitrarily and capriciously reached a different conclusion. As the EPA explained in the Proposed Rule, the EPA's review of the 2020 Technology Review found cost-effective developments in control technologies and methods of operation that demonstrated lignite-fired EGUs can achieve an Hg emission rate that is consistent with those for EGUs firing other types of coal. This finding was consistent with prior technology reviews, which often include obtaining better information about control technology performance than the Agency had available when first setting standards.[1] The 2020 Technology Review, on the other hand, did not consider developments in cost and effectiveness of demonstrated technologies, nor did it evaluate the current performance of emission reduction control equipment and strategies.

Additionally, the EPA has inherent authority to reconsider past decisions and to revise, replace or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *See, e.g., FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 42 (1983). In this instance, the EPA gathered additional information that was not considered in the 2020 Technology Review, and based on a reasoned analysis of that information determined that a more stringent Hg emission limit for lignite-fired EGUs is achievable. This was a reasoned decision by the EPA to change position from the 2020 Technology Review that was supported by evidence in the Proposed Rule. *See e.g.*, *Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 11 (D.C. Cir. 2015) (finding a "shift in EPA's position . . . was reasonable because the agency received intervening information relevant to its decision.").

Under CAA section 112(d)(6), EPA is required to review and revise emission standards "as necessary" to account for technology developments or various changes in industry practices. In so doing, the D.C. Circuit has determined that the EPA may consider costs. *Association of Battery Recyclers, Inc. v EPA*, 716 F.3d 667, 673-74 (D.C. Cir. 2013); *see also Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 11 (D.C. Cir. 2015). In *Association of Battery Recyclers*, the court found that CAA section 112(d)(2) expressly authorizes cost consideration in other aspects of the standard-setting process, such as 112(d)(6). 716 F.3d at 673-74.

As the EPA explained in the 2023 Proposal, in conducting technology reviews under CAA section 112 the EPA considers costs in various ways, depending on the rule and affected sector. For example, the EPA has considered, in previous CAA section 112 rulemakings, cost-effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues (*e.g.*, cost to revenue ratios). Further discussion regarding the EPA's assessment of costs and cost-effectiveness for the fPM standard are discussed in section IV.D.1 of the preamble.

[1] *National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review*, 85 FR 41680, 41690 (July 10, 2020); *National Emissions Standards for Mineral Wool Production and Fiberglass Manufacturing*, 80 FR 45280, 45284-45285 (July 29, 2015); *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards*, 80 FR 75178, 75201-75202 (December 1, 2015); *National Emission Standards for Coke Oven Batteries*, 69 FR 48338, 48351 (August 9, 2004).

Comment 3: Commenters stated that the EPA has no authority to revise the EGU standards under CAA section 112(d)(6) based on the information in the proposal and said the "as necessary" language of the statute limits the EPA's authority.

Commenters stated that the EPA's authority under CAA section 112(d)(6) is linked to finding developments in practices, processes, and technologies. Commenters said that the EPA found no new developments in practices, processes, and control technologies for this source category in its 2020 Final Action (85 FR 31286) and cited the EPA's review of fPM controls in the 2023 Proposal (88 FR 24854) at 88 FR 24865. Commenters said the EPA exceeded its authority under CAA section 112 by failing to identify a "development" to justify reducing the fPM standard.

Commenters said that Congress did not create the RTR process as an open-ended authority to redefine MACT standards and said CAA section 112 does not require the EPA to recalculate MACT floors under CAA section 112(d)(6). Commenters cited *National Association for Surface Finishing v. EPA*, 795 F.3d 1, 11 (D.C. Cir. 2015) and said the EPA went beyond its statutory authority by determining that "developments" under CAA section 112(d)(6) include changes in emissions data, costs, and monitoring devices. Other commenters cited *Encino Motorcars, LLC v. Navarro*, 579 U.S. 211, 221 (2016) and said the EPA must show a reasoned explanation for disregarding facts that underlay the prior policy.

Commenters said the record for the proposal does not present information sufficient to support a different conclusion since the 2020 Final Action. Commenters said that the technologies underlying the EPA's cost position have not changed since 2012 and concluded that costs are not a valid new "development" under CAA section 112(d)(6). Some commenters acknowledged that the EPA's reliance on improved fPM and Hg emissions data may be indicative of new practices, processes, or control technologies, but said the proposal does not identify the root cause of these emission reductions. Other commenters said the two "developments" identified in the proposal (related to the low levels of emissions and costs of controls) do not warrant a more stringent fPM standard under CAA section 112(d)(6) authority and said the proposal's consideration of actual emissions and costs as "developments" was inconsistent with prior EPA determinations under CAA section 112(d)(6) for coke oven batteries, ferroalloy production, and wool fiberglass manufacturing.

Commenters opposed the proposal's rationale for rejecting a fPM limit of 0.015 lb/MMBtu because "it would largely leave in place the status quo[,]" and commenters said this rationale was inconsistent with the EPA's statutory authority under CAA section 112(d)(6). Commenters said that under CAA section 112(d)(6) authority, the EPA initially determined that there are "no new practices, processes, or control technologies for non-Hg HAP." Commenters said that subsequently, the EPA moved beyond CAA section 112(d)(6) authority and re-examined changes in emissions, costs, and monitoring. Commenters said that emissions changes are outside of CAA section 112(d)(6) authority. Commenters said that the proposal relies on authorities under CAA section 112(d)(2) and (3) but said the EPA's authorities for this proposal are limited to those delineated under CAA section 112(d)(6). Commenters said the proposal does not uncover what new practices, processes, or control technologies occurred since the development of the MATS Rule in 2012 or since the reconsideration in 2020.

Commenters said the proposal relies on the same control technologies considered in 2012 (fPM: ESP and FF; Hg: combination of sorbent injection and activated carbon injection) [*NASF*, 795 F.3d at 11 ("developments" must happen after the issuance of the original rule)].

Commenters said that the EPA did present new fPM data from the Agency's WebFIRE database and collected limited information from lignite units under CAA section 114 requests, but commenters said the EPA's analysis does not present information sufficient to show any actual change in practice since the original rule. Commenters said the proposal does not include a reasonable basis for coming to a different conclusion with respect to fPM and Hg emissions from lignite units in only three years since the 2020 Final Action. Commenters also stated that the RTR process does not allow the Agency to simply revisit a standard and change its mind without sufficient scientific and technical bases. They argued that the record must support this shift in outcome [NASF, 795 F.3d at 11-12].

Commenters cited *National Association for Surface Finishing v. EPA*, 795 F.3d 1, 11 (2015) (*NASF v. EPA*) and said the Court determined that the EPA does not have the authority to revise a MACT standard in the RTR process unless developments happened after the issuance of the original rule. Commenters said that the proposal does not uncover new practices, processes, or control technologies since MATS was promulgated in 2012. Commenters said the RTR process does not allow the EPA to take the proposed actions without sufficient scientific and technical support. They argued that the proposal improperly uses the initial MACT floor authorities under CAA section 112(d)(3) when the proposal should be limited to the technology review authorities under CAA section 112(d)(6). Commenters said CAA section 112(d)(6) requires the EPA to consider "developments in practices, processes, and control technologies." Commenters said that the proposal concludes, with respect to fPM, that there are "no new practices, processes, or control technologies for non-Hg HAP" [88 FR 24868]. Commenters said that this finding should have signaled the end of the EPA's statutory inquiry for fPM. Commenters stated that the proposal then moves beyond CAA section 112(d)(6) authority and re-examines changes in emissions data, costs, and monitoring devices. Commenters said that the proposal inappropriately labels these changes as "developments" and said that emissions changes alone are outside of the statutory technology analysis. Commenters said that in *NASF v. EPA*, the EPA identified several pre-existing technologies in its analysis (control devices, HEPA filters, tank hoods, fume suppressants) and discussed improvements in the control performance resulting in emission reductions. Commenters said that the *NASF* court found this was a sufficient development because the EPA discussed the impact of the developments and examined what emissions levels could be achieved. Commenters said the key inquiry was whether the record supports a shift in analysis over time.

Commenters stated that the EPA has recalculated the fPM costs of MATS technologies and monitoring devices. They said the costs may be a valid development if technologies were originally eliminated due to cost in 2012 but are now cost-effective in 2023 – however, this is not the case here. The commenters said that the fPM technologies applied in this proposal – ESPs and FF and Hg reduction technologies were not previously eliminated due to cost. They concluded therefore, for this rulemaking, costs are not a "development." Commenters concluded that the previous record and the current proposal do not support the determination that changes in costs should be considered a "development" under CAA section 112(d)(6). Commenters also said that improved fPM and Hg emissions data are not necessarily indicative of new practices, processes, or control technologies and said observing improvements in emissions data does not end the investigation. They said the proposal must provide evidence of the actual cause(s) of emission reductions and said the proposal does not provide the root cause of reductions.

Commenters said that CAA section 112(d)(6) does not require limits to be revised when they are "achievable" as discussed in the proposal, but said the statute requires revisions "as necessary" and contingent on new developments. Commenters said that in a case such as the proposed rule, when the residual risk is acceptable with an ample margin of safety, the EPA should not issue new standards.

Commenters said that the EPA has the discretion to evaluate a range of relevant factors under CAA section 112(d)(6) and said the Agency is justified in reconsidering the 2020 Technology Review. Commenters cited the statutory text and cited *Louisiana Env't Action Network v. EPA*, 955 F.3d 1088, 1093 (D.C. Cir. 2020) ("LEAN") and said the terms "revise as necessary" and "developments" are both interpreted broadly, with reference to CAA section 112(d)(2)'s focus on "maximum" emission reductions that are "achievable." Commenters said the *LEAN* decision indicates the EPA may consider factors beyond the kinds of "practical and technological advances" specifically listed in CAA section 112(d)(6). Commenters said the 2020 Technology Review did not evaluate developments in costs or performance of controls and agreed that the proposal appropriately reconsidered the 2020 Technology Review. Commenters said the proposal's approach for evaluating cost effectiveness relative to total revenues is appropriate and said that the determination of whether it is "necessary" to revise standards under CAA section 112(d)(6) must be made with reference to the CAA section 112(d)(2) mandate. Commenters said the CAA section 112(d)(2) mandate does not suggest that the standard must provide the lowest cost.

Commenters stated that the EPA has the authority to consider new information on the impacts of coal- and oil-fired HAP emissions and cited *Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 16-17 (D.C. Cir. 2015). Commenters said this case indicates the EPA has authority to determine that "developments" include "not only wholly new methods, but also technological improvements … that could result in significant additional emission reduction."

Commenters said CEMS lead to reductions in emissions as operators detect and correct problems and said such reductions constitute a "development" that requires revisions to standards under CAA section 112(d)(6) authority.

Response 3: The EPA disagrees with commenters that allege the EPA lacks the authority to revise EGU standards under CAA section 112(d)(6) or review past decisions, as discussed in Response 2 above. The EPA further disagrees with commenters that it did not identify a "development" sufficient to justify reducing the fPM standard used as a surrogate for non-Hg metal HAP. The EPA's review revealed two important changes in the coal-fired EGU industry related fPM (used as a surrogate for non-Hg metal HAP) that occurred since the EPA initially promulgated MATS in 2012. First, the large majority of units are reporting fPM emissions significantly below the current emission limit; and second, the fleet is achieving these lower emission levels at lower costs than the EPA assumed in promulgating the original MATS fPM emission limit. The EPA finds these are cognizable developments, which are clearly illustrated elsewhere in this record. As other commenters noted, in *National Association for Surface Finishing v. EPA*, the D.C. Circuit found the EPA "permissibly identified and took into account cognizable developments" based on the EPA's interpretation of the term as "not only wholly new methods, but also technological improvements." 795 F.3d at 11 (D.C. Cir. 2015). Similarly here, the EPA identified a clear trend in control efficiency, costs, and technological improvements, which the EPA is accounting for in this action.

The EPA's interpretation of "developments" under CAA section 112(d)(6) to include the changes the EPA identified for non-Hg metal HAP controls is also consistent with its statutory authority. CAA section 112(d)(6) broadly requires the EPA to "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards[.]" Nothing in the language of the statute suggests "developments" should be limited to only wholly new developments as some commenters suggest. This is consistent with the EPA's interpretation of "developments" discussed in technology reviews for coke over batteries,[2] ferroalloy production,[3] and wool fiberglass manufacturing,[4] all of which considered improved control efficiency a "development" under the CAA section 112(d)(6) technology review. Based on the EPA's authority under this provision, it is the EPA's responsibility to if determine if such developments, in consideration of costs and other factors, warrant updates to emissions standards. But that requirement in no way means that in every instance the EPA identifies a "development" under a CAA section 112(d)(6) technology review, that the EPA must necessarily revise standards.

The EPA is also acting consistently with the Supreme Court's direction when it stated, "Agencies are free to change their existing policies as long as they provide a reasoned explanation for the change." *Encino Motorcars, LLC v. Navarro*, 579 U.S. 211, 221 (2016). As demonstrated throughout this record, the EPA provided a through explanation of the reasons for this action that took account of facts and circumstances underlying prior decisions, and then built upon those decisions based on new information. As other commenters point out, CAA section 112(d)(2) focuses on the EPA determining "maximum" emission reductions that are "achievable." In this action, under the EPA's technology review authority it considered developments in practices, processes, and control technologies to determine if more stringent standards are achievable than those initially set by the EPA in establishing MACT floors, based on developments that occurred in the interim. *See LEAN v. EPA*, 955 F.3d 1088, 1097-98 (D.C. Cir. 2020). Based on a consideration of costs and other factors, the EPA finds that the revised standards are achievable.

The EPA agrees with commenters that CAA section 112 does not require the EPA to recalculate MACT floors under the CAA section 112(d)(6) technology review. Further discussion regarding the EPA's rationale for adopting the final fPM standard and assessment of costs and cost-effectiveness for the fPM standard are discussed in section IV.D.1 of the preamble.

---

[2] 69 FR 48338 (proposed Aug. 9, 2004).
[3] 79 FR 60238 (Oct. 6, 2014).
[4] 82 FR 40970 (Aug. 29, 2017).

Comment 4: Commenters cited significant emission reductions from EGUs since 2010 and stated that further HAP reductions are not warranted under CAA section 112(f)(2) authority. Commenters said the results from this residual risk assessment provide a strong scientific foundation for the EPA to conclude that the current MATS limitations provide an ample margin of safety to protect public health in accordance with the requirements of CAA section 112(f)(2). Commenters cited risk metrics in the RIA and said that the EPA has not demonstrated an unacceptable risk for lignite-fired EGUs under CAA section 112(f)(2), and said the EPA has no authority to issue RTR in the absence of unacceptable risk.

Commenters disagreed with the proposal's reliance on the Court's decision in *La. Envtl. Action Network v. Envtl. Prot. Agency*, 955 F.3d 1088 (D.C. Cir. 2020) (*LEAN*), as support for the position that MACT standards may be revised even when the review under CAA section 112(f)(2) finds an ample margin of safety. Commenters said that *LEAN*'s only proposition for an RTR is that the EPA is obligated to include listed HAP that were not included under the original CAA section 112(d)(3) standards. Commenters said that the *LEAN* decision cites *Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 4 (D.C. Cir. 2015) which allows for strengthening of standards when "developments" occur but does not require it.

Commenters said that the proposal's consideration of cost under CAA section 112(d)(6) is beyond the authority granted to the EPA in the statute. Commenters said that the EPA's authority under CAA section 112(d)(6) is not an opportunity to re-apply the MACT floor requirements under CAA section 112(d)(3) to units that are already subject to MACT standards.

Commenters from a coal-producing state said the proposal was unjustified and conflicts with technical data and the record assembled by the agency itself, citing the EPA's 2020 determinations related to "ample margin of safety" and related to "no new practices, processes, or control technologies…."

Commenters said that under CAA section 112(c)(9), the EPA has the authority to remove the EGU source category because the risk estimates are one-tenth of the acceptable level. Commenters said that the EPA must factor its findings under CAA section 112(f)(2) into its technology cost analysis and said that the EPA's modeling demonstration indicates that it is unreasonable under CAA section 112 authority to impose additional regulatory burden on lignite plants.

Commenters agreed with the EPA's "two-pronged" interpretation that CAA section 112(d)(6) provides authorities to the EPA that are distinct from the EPA's risk-based authorities under CAA section 112(f)(2). Commenters said that if the criteria under CAA section 112(d)(6) are met, the EPA must update the standards to reflect new developments, without regard for risk assessments under CAA section 112(f)(2). Commenters said the technology-based review conducted under CAA section 112(d)(6) need not account for any information learned during the residual risk review under CAA section 112(f)(2), unless that information pertains to statutory factors under CAA section 112(d)(6), such as costs. Commenters concluded that CAA section 112(d)(6) requires that EPA promulgate the maximum HAP reductions possible where achievable at reasonable cost without regard for health or environmental impacts.

Response 4: As discussed throughout this record, updating fPM standards to bring the worst performing units up to a level where the majority of units are performing serves Congress's mandate to the EPA to continually consider developments and to ensure that standards account for developments "that create opportunities to do even better." *Louisiana Environmental Action Network (LEAN) v. EPA*, 955 F.3d 1088, 1093 (D.C. Cir. 2020). Discussion regarding the EPA's authority to conduct the CAA section 112(d)(6) technology reviews independent of the Agency's residual risk review is in section IV.C.1 of the preamble.

Comment 5: Commenters said the EPA does not have the statutory authority to revise monitoring requirements in an RTR.

Commenters said that the EPA has authority to require CEMS for PM, HCl and any other pollutants regulated by MATS to ensure EGUs are complying with standards and cited CAA sections 112(b)(5), 114(a)(1)(C), and 114(a)(3). Commenters said that none of these CAA provisions explicitly requires the EPA to consider cost and cited *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 561 (D.C. Cir. 2015) as supporting case law that indicates certain monitoring requirements do not amount to "beyond the floor" standards under the EPA's CAA section 112(d)(2) authority.

Response 5: The EPA disagrees with commenters that it lacks authority to update compliance demonstration requirements to require PM CEMS under CAA section 112(d)(6). As discussed further in section IV.D.2 of the final preamble, the EPA finds that the benefits of PM CEMS to provide real-time information to owners and operators (who can promptly address any problems with emissions control equipment), to regulators, to adjacent communities, and to the general public, further Congress's goal to ensure that emission reductions are consistently maintained.

Comment 6: Commenters cited CAA section 112(d)(1) and said the proposal exceeds the EPA's statutory authority by removing the non-Hg, individual metal HAP standards and replacing them with fPM as a surrogate. Commenters said the EPA has no authority under CAA section 112 to regulate only PM. Commenters said there must be a compliance option based on the target HAP. Commenters said CAA section 112(d)(6) does not provide the EPA authority to revise compliance methods and cited the statutory references to reviewing and revising "emissions standards." Commenters cited *Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) and said that the EPA may use a surrogate if it is reasonable but said eliminating the actual non-Hg limits is not within the EPA's authority to establish surrogates. Commenters said that the EPA's justification that few sources use the HAP-metals compliance option does not support elimination of the option. Commenters also said that the Executive Order 13990 did not instruct the EPA to analyze monitoring. Commenters said that if the EPA removes the non-Hg, HAP-metals limits then the EPA must also remove the surrogate limit.

Response 6: In *National Lime Ass'n v. EPA*, the D.C. Circuit found "[t]he EPA may use a surrogate to regulate hazardous pollutants if it is 'reasonable' to do so."233 F.3d 625, 637 (D.C. Cir. 2000). In that case, the court found "the use of PM as a surrogate for HAP metals is not contrary to law." *Id.* at 639. Specific to the Portland Cement Kilns at issue in that case, the court also found PM is a reasonable surrogate for HAP metals. *Id.* While the court instructed the EPA that it "may need to reconsider whether PM is an appropriate surrogate for HAP metals" when the EPA updated standards, *id.*, the court said nothing to suggest the EPA cannot use a surrogate as the sole emissions limit for a particular type or class of HAP. For further information regarding the EPA's technical justification to use fPM as a surrogate see Chapter 2.2, below.

Comment 7: Commenters said that the EPA's authority under CAA section 112(d)(6) only allows revisions to MACT standards if revisions are "necessary." Commenters said that the proposal is imposing beyond-the-floor standards without adequately considering cost and cited *Michigan v. EPA*.

Commenters cited *NRDC v. EPA*, 529 F.3d 1077, 1083 (D.C. 2008) and said that CAA section 112(d)(6) does not require the EPA to recalculate the MACT floor. Commenters said that the review process is more limited and defined by statute as the one-time residual risk review and the octennial technology review. Commenters cited *Association of Battery Recyclers Inc. v. EPA*, 716 F.3d 667, 673 (D.C. Cir. 2013) and said costs are implied as a component of the RTR analysis.

Commenters cited *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981) and said the case grants the EPA discretion in weighing cost, energy, and environmental impacts, recognizing the Agency's authority to take these factors into account "in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." Commenters said that the EPA has authority to set costs that are reasonable for the industry even if they are not reasonable for every facility.

Commenters acknowledged that the EPA has discretion to consider cost effectiveness under CAA section 112(d)(2) and cited *NRDC v. EPA*, 749 F.3d 1055, 1060-61 (D.C. Cir. 2014) but also said that the dollar-per-ton metric is less relevant under CAA section 112 than under other CAA provisions because the Agency is not charged with equitably distributing the costs of emission reductions through a uniform compliance strategy, as the EPA has done in its transport rules (citing *NRDC v. EPA*, 749 F.3d 1055, 1060-61 (D.C. Cir. 2014)). Commenters said that the Agency must require maximum reductions of HAP emissions from each regulated source category and has no authority to balance cost effectiveness across industries.

Response 7: In this action, the EPA is acting under its authority in CAA section 112(d)(6) to "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards" promulgated under CAA section 112. As the EPA explained in the proposal, this technology review is separate and distinct from other standard setting provisions under CAA section 112, such as establishing MACT floors, conducting the beyond-the-floor analysis, and reviewing residual risk. Comments regarding costs considerations following from the *Michigan v. EPA* decision are discussed in section 8.4 of this document.

Comments regarding the EPA's assessment of costs and cost-effectiveness for the fPM standard are discussed in section IV.C.1 of the preamble.

Comment 8: Commenters said that the EPA does not have the authority to wait to address the lack of standards for dioxins, benzene, carbon disulfide, dichloromethane, and toluene. Commenters said that the EPA must develop standards for these HAP in the RTR because CAA section 112 requires emission limits for each HAP emitted by a source category and cited 42 U.S.C. § 7412(d); *Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 633-634 (D.C. Cir. 2000); *Sierra Club v. EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007).

Response 8: As explained in the 2023 Proposal, the EPA's review of new technology and methods of operation conducted as part of this technology review found no developments that would result in cost-effective emission reductions of organic HAP. Further, as explained in Chapter 5.1 of this document, the EPA plans to continue to review a petition for reconsideration from environmental organizations that sought the EPA's reconsideration of organic HAP work practice standards and will respond to the petition in a separate action.

Comment 9: Commenters opposed the proposed changes to the fPM standard and the proposal to eliminate the quarterly testing compliance option. Commenters said the proposal exceeds the EPA's statutory authority under CAA section 112(d)(6) and that the proposed rule would impact facilities owned or operated by the municipal power agency. Commenters said that the Act's RTR process is not intended to continually revise standards but is to address residual risk that becomes addressable through new technologies and processes. Commenters said revisions should be precipitated by new developments, not changes in analysis.

Response 9: Discussion about the EPA's authority under CAA section 112(d)(6) is discussed above in response to comments 3 and 4 in this section and in section II.A of the preamble. The EPA responded to comments about the distinction between the technology review and residual risk review in section IV.C.1 of the preamble. As the EPA explained in sections II.A and II.E of the preamble, this action is a result of the EPA's review of the 2020 Technology Review.

Comment 10: Commenters cited the omission of monetized benefits for HAP reductions on page 26 of the *NAAQS PM RIA* published in December of 2022 and said that the EPA has not justified the proposal's claim that revisions to HAP standards balance CAA section 112's direction to achieve maximum reductions with the statutory factor of cost. Commenters also said the CAA does not authorize the EPA to promulgate a rule based completely on co-benefits as proposed and said that the EPA has not economically justified the proposed rule based on CAA section 112 mandates for HAP reductions. Commenters were opposed to the proposal's reliance on criteria pollutant co-benefits and cited the process delineated in CAA section 110 of the Act for attainment of NAAQS. Commenters said the proposal is inconsistent with CAA section 110 because it uses CAA section 112 to reduce $PM_{2.5}$ emissions. Commenters also said that the Act does not authorize the EPA to assign benefits to a PM rule that include benefits in areas attaining the PM or ozone NAAQS, citing CAA section 109(b)(1).

Commenters said the proposal considers co-benefits associated with CO_2 emission reductions and said that the EPA does not have the authority to consider shifting generation from units that emit CO_2 to units that do not emit CO_2 and cited *West Virginia v. EPA*, 142 S.Ct. 2587, 2614 (2022).

Response 10: It is well established that the EPA may use a surrogate emission standard under CAA section 112,[5] such as it has here by using fPM emissions as a surrogate for non-Hg metal HAPs. Accordingly, the EPA is acting under its authority under section 112 of the CAA and not section 110, as commenters suggest.

Comment 11: Commenters said the proposal would amount to a regulatory taking from lignite surface mine owners because lignite mine owners have made significant investments based on current standards for HAP emissions, and commenters said lignite mine owners are entitled to just compensation for any regulatory taking.

Response 11: The EPA disagrees with commenters that this rule constitutes a taking within the meaning of the Fifth Amendment.

Comment 12: Commenters said that the EPA's authority under CAA section 112(d)(6) is distinct from the EPA's authority to make the A&N determination under CAA section 112(n)(1)(A) but that information compiled for the A&N proceedings, including hazards and costs, can inform the EPA's analysis under CAA section 112(d)(6).

Response 12: The EPA agrees with commenters that its authority to perform the technology review is distinct from the EPA's authority for the appropriate and necessary finding.

Comment 13: Commenters said the EPA lacks CAA section 112 authority to set emissions standards in the proposal because the EPA inappropriately determined that it was "appropriate and necessary" to list EGUs as a source category under CAA section 112. Commenters said the 2023 A&N finding is unsound because risk-levels and costs were not weighed as required in *Michigan v. EPA*. Commenters cited portions of the risk assessment in the A&N finding and said that the finding did not have sufficient information to quantify the benefits used to justify the decision that regulating EGU HAP was "appropriate." Commenters also said that the EPA's 2023 Revocation is unsound because it departed from the EPA's statutory requirements for determining risk without adequate explanation. Commenters said that the information provided by and relied upon by the EPA in the 2023 Revocation indicates that the risk associated with EGU HAP has always been below the level the EPA deems acceptable, with an ample margin of safety for sensitive populations.

Response 13: Comments regarding the EPA's appropriate and necessary finding pursuant to CAA section 112(n)(1) are outside the scope of this rulemaking.

Comment 14: Commenters requested that the EPA use authorities under the CAA, Executive Order 13990, and Executive Order 12898 to take the following actions: (1) withdraw the proposed rule and complete CAA section 112(d)(6) closer to the eight year milestone in the statute or earlier if advancements in technologies occur, or (2) create a subcategory for existing EGUs employing wet scrubbers without ESP or FFs until the next RTR, and (3) create a retirement subcategory that allows existing units to meet the current standard for fPM so long as

[5] *See Nat'l Lime Ass'n*, 233 F.3d at 637.

they opt into the retirement subcategory within 18 months after promulgation with a retirement date no later than December 31, 2035. Commenters said the requested retirement subcategory would allow operations past 2035 for units essential to reliability as determined by reliability authorities.

Commenters said that the EPA should use its authority to create subcategories for units that elect to retire by a date certain and cited recent proposed rules for EGUs at 88 FR 33245 (GHG Standards and Guidelines for Fossil Fuel-Power Plants) and at 88 FR 18824, 18837 (Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category).

Response 14: The EPA responded to the comment about creating a retirement subcategory in section IV.C.1 of the preamble and explained its rationale for the updated fPM standard (as a surrogate for non-Hg metal HAP), in section IV.D.1 of the preamble. The EPA disagrees with commenters that it should create a subcategory for existing EGUs with wet scrubbers without ESPs or FF, and the Agency does not find such a subcategory is appropriate. The EPA further disagrees that it should withdraw this action to complete a technology review closer to eight years after the 2020 Technology Review. As the EPA explained in sections II.A and II.E of the preamble, this action is a result of the EPA's review of the 2020 Technology Review.

Comment 15: Commenters responded to the EPA's solicitation for comment on what should qualify as an enforceable mechanism for exempting units from certain proposed requirements. Commenters said that all NSR permits and APD-CERT registrations should qualify as enforceable mechanism when issued by a state with a federally approved or delegated permitting program.

Response 15: The EPA requested comment on whether EGUs should be able to continue to use quarterly emissions testing past the proposed compliance date for a certain period of time or until EGU retirement, whichever occurs first, provided the EGU is on an enforceable schedule for ceasing coal- or oil-fired operation; and on what would qualify as an enforceable schedule. The EPA address comments on this topic in Chapter 3 of this document.

CHAPTER 2

2. Filterable Particulate Matter Emission Limit (as a Surrogate for Non- Hg HAP Metals)

2.1 General

Comment 1: Overview of Comments Opposed to the Proposed 0.010 lb/MMBtu fPM limit:

- More stringent limit is not warranted; EPA has not adequately supported the proposed limit.
- EGUs will not be able to comply on a continuous basis with more stringent limit (unit variability, QA/QC requirements for PM CEMS); limit should not change.
- Ratcheting down standards discourages facility efforts to minimize emissions beyond legally required levels; achieving emission rates below standard does not constitute "development in practices, processes, and control technologies."
- Reducing the standard accompanied by more restrictive monitoring requirements adds to the regulatory burden of affected sources and permitting authorities.
- Continuing downward trend in HAP emissions from coal-fired EGUs, revising the standards merely to accelerate this trend slightly is not necessary, particularly given the potential for adverse effects on reliability resulting from early retirements; Proposed change to the standard will do little to further reduce emissions.
- As more capacity and generation shift away from coal due to Inflation Reduction Act (IRA), regulatory, and economic factors, the total annual fPM and HAP emissions from the industry will decline, regardless of whether the fPM standard is made more stringent especially with the addition of IRA incentives to shift more generation to lower-emitting sources.
- Likely impracticable for existing units, especially those with decades of service and/or planning to cease coal-firing operations within the next six years.

Response 1: The EPA acknowledges and thanks the commenters for providing these comments. We have discussed the rationale for the final emissions standards in section IV.D of the preamble.

Comment 2: Overview of Comments in Support of the Proposed 0.010 lb/MMBtu fPM limit:

- Based on developments in cost, effectiveness of controls, improved practices, improvements in monitoring and ESP/FF technology, a revision to limit is warranted.
- CAA section 112, including the technology review, was intended to improve performance of lagging industrial sources, and a standard that falls far behind what the vast majority of sources have already achieved is inadequate.
- Reductions in emissions of criteria pollutants below the NAAQS thresholds can lead to significant health benefits, and it is appropriate to consider the benefits associated with

these reductions in the 2023 Proposal, specifically given these benefits are especially important for the elderly and asthmatic children sensitive to the adverse health effects caused by PM at levels below the NAAQS.

- Proposed revised fPM limit of 0.010 lb/MMBtu for existing coal-fired EGUs is reasonable and achievable and slightly greater than the fPM emission limit required for new and reconstructed units that commenced construction, reconstruction or modification after May 3, 2011, and are subject to NSPS subpart Da.

Response 2: EPA agrees with commenters that developments in the cost and effectiveness of PM control technologies, as well as improved practices at EGUs warrant a revision of the fPM standard to a more stringent level. As described in the 2023 Proposal (88 FR 24868), most coal-fired EGUs are reporting fPM emission rates well below the current emission limit of 0.030 lb/MMBtu and the fleet is achieving these performance levels at lower costs than assumed during promulgation of the original MATS fPM emission limit. We have discussed the rationale for the final emissions standards in section IV.D of the preamble.

Comment 3: Overview of Comments Opposing the 0.006 lb/MMBtu more stringent limit:

- Creates a host of obstacles, making the standard unrealistic to implement, such as cost effectiveness and PM CEMS measurement uncertainty and correlation.
- Feasibility and cost considerations across the industry even though this lower level may be achievable for some units with a range of control configurations. Commenters do not feel this more stringent limit accurately reflects the current technology and capabilities of the entire EGU industry and is completely untenable.
- EPA should only consider moving toward the more stringent level of 0.006 lb/MMBtu if the agency also considers strategies that are developed with, and would help, some of those hardest-hit areas work through those difficulties with the tighter standard (*e.g.,* providing additional time or resources), so that additional emission reductions could be realistically realized from these areas.
- Because available public data demonstrate that imposition of the proposed standard of 0.010 lb/MMBtu is not cost effective, no standard that is more stringent than the proposed standard can be considered cost effective. Commenters stated that the benefits do not exceed the costs.

Response 3: The Agency acknowledges and thanks the commenters for providing these comments, and the final rationale for the emission standards is discussed in section IV.D of the preamble.

2.2 Use of fPM as a surrogate

Comment 1: Commenters requested that the EPA not rely on the representative use of fPM emissions as a surrogate for total non-Hg metal HAP to evaluate the three more stringent emission limits. Commenters reiterated that 96% of existing coal-fired capacity without known retirement plans before the proposed compliance period already have demonstrated an emission rate of 0.015 lb/MMBtu (LEE qualification) or lower, 91% of existing coal-fired capacity have demonstrated an emission rate of 0.010 lb/MMBtu or lower, and 72% of existing coal-fired capacity have demonstrated an emission rate of 0.006 lb/MMBtu or lower and suggested that the Agency not use this as justification for setting the proposed fPM limit at 0.010 lb/MMBtu.

Commenters stated that the EPA lacks authority to lower the PM standard because PM is not the pollutant of concern. They reiterated that when the 2012 MATS Final Rule was originally imposed on electric utilities, the EPA determined that sampling of individual non-Hg metals was difficult, time consuming, and costly. Based on those concerns, the EPA allowed the use of fPM as a surrogate for metallic HAP since research had shown that facilities where PM was well controlled were significantly lower in non-Hg metal emissions. Commenters agreed the EPA correctly used that finding to determine that when PM was below 0.030 lb/MMBtu, the risk due to non-Hg metals was below the EPA required risk level. They remind the EPA that this finding confirmed that EGUs do not pose an unacceptable risk to human health and the environment. Commenters indicated those risk values already consider the highest risk from any HAP, and therefore already fully account for any remaining risk from any metallic HAP. Commenters noted that the EPA may only utilize a surrogate to regulate HAP emissions if it is “reasonable” to do so, which the EPA has failed to satisfy the “reasonable” standard in the 2023 Proposal. They continued that for the EPA’s use of a surrogate to be “reasonable,” the EPA must determine:

- The relevant HAP are invariably present in the proposed surrogate;
- Control technologies for the proposed surrogate indiscriminately capture the relevant HAP along with other pollutants; and
- The control of the surrogate is the only means by which facilities achieve reductions in emissions of the HAP.

The commenters stated the Agency fails to establish that the control of the surrogate is the only means by which facilities control non-Hg metallic HAP emissions. They reiterated that with the 2023 Proposal the EPA is proposing to significantly lower the fPM standards and completely remove the individual non-Hg standards. Commenters expressed concern that PM is not a HAP and was only used by the EPA as a surrogate for non-Hg HAP; thus, it's difficult to understand how the EPA has authority to lower a constitute which is not even included in the list of regulated HAP. Commenters indicated there is no need to further reduce these emissions by lowering the fPM emission standard and suggested if the EPA wishes to lower the limits of non-Hg metals, the Agency should first lower the individual limits and then determine the level of reduction for the surrogate which is proportional to the new non-Hg metals limits. Commenters noted that the EPA has wholly failed to attempt such rationale here, ignoring a highly relevant factor in determining whether individual and total metal HAP standards should continue to be included in the rulemaking. Commenters concluded the EPA's process in setting a new proposed PM standard is backwards and should be reevaluated based on the individual non-Hg metals limits. Commenters stated that direct monitoring of all phases of all HAP metals is an enhancement over the monitoring of a surrogate (PM) for some HAP metals and one phase of Hg. Commenters further stated that Congress gave the EPA a mandate to require enhanced monitoring and major sources are required to use enhanced monitoring such that there is reasonable assurance of HAP control.

Commenters in general supported the EPA's proposal to remove the total and individual non-Hg metals emission limits from the MATS rule to rely solely on the fPM limit as a surrogate for non-Hg metal HAP. They conveyed to the extent that these HAP are not addressed adequately through this surrogate regulation, additional requirements may be necessary.

Commenters stated while fPM is not classified as a HAP under the CAA, non-Hg metals and other elements like arsenic and selenium comprise a significant part of $PM_{2.5}$. Commenters expressed concern over several non-Hg trace elements including cadmium and lead which are considered systemic toxicants that are known to induce multiple organ damage, even at lower levels of exposure; because of this they recommend that the EPA consider an even more protective fPM limit of 0.006-0.007 lb/MMBtu. They continued that these primary particles, along with the secondary particles that are formed as a result of chemical reactions of SO_2 and NO_x emissions, carry life-threatening risks. Commenters stated that $PM_{2.5}$ particles are smaller than the diameter of a human hair, making them small enough to lodge deep within the respiratory tract when inhaled. Commenters expressed concern that exposure to $PM_{2.5}$ can lead to respiratory harm, including asthma exacerbations, inflammation of the upper and lower airways, and even respiratory mortality. They continued that $PM_{2.5}$ also causes cardiovascular harm including myocardial infarction, congestive heart failure, cardiac arrhythmias, and strokes; and that the EPA has also determined that exposure to $PM_{2.5}$ is likely to cause cancer.

Response 1: We disagree that the EPA lacks authority for lowering the fPM standard as PM is not the pollutant of concern. In establishing fPM as a surrogate for the non-Hg metal HAP for the original MATS rulemaking, the EPA explained that most of the non-Hg metal HAP are present overwhelmingly in the fPM fraction. Selenium may be present in both the fPM fraction or as an acid gas, SeO_2, in the condensable PM fraction, which is controlled by the emission limit for acid gas HAP. As non-Hg HAP metals are still components of fPM, regardless of what the limit is, and that PM controls, such as ESPs and FF, control at least 99% of the non-Hg HAP metals, the use of fPM as a surrogate continues to be reasonable. In addition, in response to comments that Congress gave the EPA a mandate to require enhanced monitoring and major sources are required to use enhanced monitoring such that there is reasonable assurance of HAP control, the requirement to use PM CEMS for compliance demonstration purposes succeeds in that mission. Lastly, the EPA is finalizing revised total and individual non-Hg HAP metal emission limits that are lowered proportionally to the revised fPM standard, as described in more detail in section IV.D.1 of the preamble.

2.3 Data & Analysis Concerns

2.3.1 Data

Comment 1: Commenters stated the EPA makes faulty assumptions that intentionally push the fPM emissions baseline lower by selecting the lowest fPM rate from selected reference quarters. Commenters concluded that the EPA only used data from specific quarters in 2017, 2019, and 2021 which were not all inclusive of company's data or the companies were not able to identify their units or replicate the EPA's dataset.

Commenters indicated that the EPA's evaluation of fPM emissions from existing coal-fired EGUs is misleading, incomplete, and may be a misrepresentation of actual fPM emissions. Commenters referenced several issues with the EPA's evaluation and data set:

- All quarters of available 2017 through 2021 data were not included;
  - Commenters requested the EPA provide justification for the Agency's selection of the data, why reliance on the selected data is appropriate, and why certain quarterly data between 2017 through 2021 were excluded, so that interested stakeholders can verify the accuracy and representativeness of the underlying unit-specific data.
- Only selected quarters with the lowest emissions for some units were included;
- Fails to consider whether the units are able to achieve 0.010 lb/MMBtu fPM or a lower emission rate for each quarter during that time period due to the Agency's use of best-case lowest fPM values;
- Commenters conveyed their observations that the data illustrates a large degree of variation in the 30-day averages over-time, and the fact that the emissions happen to be low during a single quarter does not indicate that that same level of performance can be consistently achieved over time;
- The analysis excluded other quarters with higher emissions;
- Some units with no current plans to retire or switch to natural gas were omitted;
- The data set includes periods when coal units were co-firing with natural gas, which will bias the data set artificially low; Commenters suggested that since co-firing units continue to have the capability to combust coal, all of their emissions data is reported as subject to MATS. However, co-firing natural gas inherently results in significantly reduced fPM emissions, which could bias the data set low. Commenters questioned discrepancies between data sets of the 2023 Proposal and cited reference documents which potentially bias information used as rationale for development of this 2023 Proposal;
- Some units that are slated for retirement were incorporated despite the EPA's claim that these units were excluded;
- Commenters stated the EPA deliberately biased the baseline from PM CEMS data low. They stated instead of using all PM CEMS data, the EPA arbitrarily selected quarters of PM CEMS data and relied on 30-day averages observed on the last day of the quarter. This approach also ignores the natural variability of unit operation.
- The data fails to recognize that some units have converted to natural gas co-firing.
- Commenters stated that the EPA's failure to include units that will shut down or no longer burn coal/oil by December 31, 2028 does not appropriately account for units that are likely emitting fPM at levels closer to the current standard than the more stringent proposed fPM limit.

- Commenters further noted that the EPA employed a different data selection methodology for each of those years and based on type of compliance measure used (CEMS vs. stack test).
- Commenters suggested that the EPA analyze more comprehensive historical data sets across a longer timeframe rather than using a snapshot of EGUs demonstrating compliance with the proposed limit during selected quarters prior to concluding that continuous compliance with the proposed limit is achievable.
- Comment: They also suggested if the EPA eliminates performance testing as a compliance option, then the EPA should rely exclusively on a robust set of PM CEMS data in terms of the number of units and datapoints used.

Commenters also provided unit-specific comments and observations:

- Commenters stated the Coronado PM CEMS data that the EPA's referenced for the proposal are not representative of the unit operations or capabilities, stating 10 of 20 quarters reported 90^{th} percentile fPM rates higher than the proposed 0.010 lb/MMBtu fPM standard and 16 of 20 quarters exceeded the baseline fPM rate of 0.0086 lb/MMBtu estimated at proposal. The Coronado operator reports that quarter three of 2019, which is used in the EPA's dataset, reflects normal operation without any maintenance or optimization activities that could have impacted emissions during that quarter.

- Commenters requested correction of what they said are two errors in the EPA's January 2023 Memorandum re: the 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category. They said in Appendix C, Nearman Creek facility (ID 6064_B_N1) is listed as having a capacity of 240 MW. They said the correct capacity for Nearman Creek is 268 MW. The commenters also said that Nearman Creek is identified as having both an ESP and a baghouse as PM controls. They said this is incorrect as Nearman Creek does not have an ESP.

Commenters recommended that the EPA correct the deficiencies, as well as make the Agency's statistical analysis or Python code used for the fPM evaluation available for public review to ensure that the proposed fPM limit is not deemed arbitrary and capricious.

Response 1: EPA appreciates the commenters' observations regarding issues about the fPM data. The rationale for the final standards is discussed in section IV.D of the preamble.

For the proposal, the Agency selected quarterly data during the time of year where electricity demand is typically higher (winter and summer) and when EGUs tend to operate more with higher loads, as described in the 2023 Technical Memo (Docket ID No. EPA-HQ-OAR-2018-0794-5789). The Agency did not intentionally exclude quarters with higher emissions, however, the review focused on evaluating the lowest fPM rates EGUs had historically achieved with existing PM controls. However, if the Agency were able to pull data for every quarter for every EGU in this analysis, it would only lower the lowest achieved fPM rate, therefore potentially decreasing PM upgrade costs to meet a lower fPM limit. The Agency disagrees that the data set should remove potential periods when coal units were co-firing with natural gas, as the Agency is not responsible or controls how particular EGUs decide to operate.

In revising the analysis, the Agency reviewed the impacted facility list and made changes based on commenters feedback, such as removing EGUs that have converted to natural gas. EGU retirement plans were updated based on the comments received and the most recent NEEDS database. Many commenters did not provide specific EGUs to include or remove from the analysis, so we were unable to ensure these updates were included. Regarding unit-specific comments, EPA's analysis is based on net summer generating capacity, which has been reported to EIA as 240 MW for Nearman Creek. EPA will update our control information to reflect the absence of a cold-side ESP at this unit.

In response to concerns about the use of limited quarterly compliance data, EPA expanded the analysis to include all available fPM compliance data for 60 EGUs at 18 facilities, including EGUs that the 2023 Proposal indicated would be impacted by the 0.010 lb/MMBtu fPM limit. The EPA acknowledges commenters requested a review of compliance data spanning longer time periods (*e.g.,* 2017-2021 or all available compliance data since promulgation of MATS). Obtaining quarterly compliance data for nearly 300 coal-fired EGUs even for a shorter period of 2017-2021 would require 6,000 separate downloads from CEDRI (5 years of quarterly data for 300 EGUs), producing pdf files unable to be directly evaluated through programming languages and requiring translation of either 3 stack runs and averages or daily 30-day rolling averages for the quarter into Excel. Electronic reporting requirements taking effect in 2024 will enable the Agency to review compliance data in a more time-effective manner. In addition, reviewing all available compliance data for all EGUs would only potentially lower the lowest achieved fPM rate used in the PM upgrade and cost assumptions. Thus, review of additional data could potentially lower costs.

The Agency focused its additional data review on the highest-emitting EGUs, spanning a variety of PM controls, locations, and capacities, and include the Coronado units that the commenters reference above (see Case Study 15 in Attachment 2 to the 2024 Technical Memo, available in the docket), as well as the Gallatin (Case Study 20), Trimble (Case Study 22), and Mill Creek (Case Study 23) facilities that commenters discuss in their comments (Docket ID No. EPA-HQ-OAR-2018-0794-5910). The review of a more comprehensive historical data set reveals the vast majority of EGUs analyzed have long-term records consistently meeting fPM rates of 0.010 lb/MMBtu or lower. For instance, 22 of 30 quarters, (spanning from 2015 to the end of quarter 1 2023, which is more data than the commenters evaluated) assessed for the Coronado facility indicate an average fPM rate equal or less than 0.010 lb/MMBtu. Similarly, the 30-boiler operating day average PM CEMS data from Coronado are greater than 0.010 lb/MMBtu only approximately 30 percent of the time. The review of a more comprehensive data set also revealed the top 20 fPM emitting EGUs discussed in the 2023 Proposal have larger variations in fPM quarter to quarter. As a result of the additional data review, the Agency determined the lowest quarter's 99^{th} percentile is effective to identify EGUs that have historically achieved lower fPM rates despite not being required to do so and without additional capital investments. In order to account for the unit-specific variability, the EPA also assesses the average fPM rate when estimating whether additional improvements may be needed. The details of this expanded analysis, including code plotting historical fPM rates, is included in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category," available in the docket.

Comment 2: Commenters attempting to verify the accuracy of the underlying source-specific fPM data, evaluated their unit-specific data across a wider time frame and found that while some of their units may have met the 0.010 lb/MMBtu or 0.006 lb/MMBtu fPM emission rates from time to time, their units did not consistently achieve those rates as will be required if the EPA finalizes its proposed requirement that EGUs must use a PM CEMS to demonstrate compliance with the fPM standard making compliance demonstrations more difficult to achieve.

Commenters requested that the EPA provide additional information to allow commenters to fully evaluate whether the more stringent standard of 0.006 lb/MMBtu is achievable.

Response 2: The use of PM CEMS for compliance, while continuous, will also provide owners and operators with real-time data to improve operations. Additionally, the standard using PM CEMS is a 30-day rolling average, compared to averages of three stack test runs. The additional real-time data availability and longer averaging time period will help EGUs achieve continuous compliance.

Comment 3: Commenters recognized that while the original MACT floor analysis included 130 units, PM lb/MMBtu data for only 82 of those units was available in the 2019 data, with the difference driven largely by unit retirements and suggest the 2019 emission values are higher on average and show a greater degree of variability than the MACT floor data suggest, especially given one data point for a best performing unit was above the current limit. A few commenters provided a comparison of the 2019 data compiled by the EPA in the merged PM data spreadsheet with the data collected by the Agency during the original 2012 MATS Final Rule ICR that illustrates there have been no changes in performance of either the units used to set the MACT floor or the units that the original 2012 MATS Final Rule ICR data showed had achieved 0.015 lb/MMBtu that warrants a revision.

Response 3: The EPA disagrees with commenters with their conclusion that there have been no changes in performance of EGUs. First, while the original MACT standards were based off the 130 best performing sources, the review of the 2020 Technology Review found most of the 274 sources evaluated—not only the best performing in 2012— were performing well below the MACT standard, as illustrated in Figure 1 of the proposal preamble (88 FR 24868). Alternatively, the UPL mean from the MATS ICR (the average of the 130 average fPM test results) was 0.00216 lb/MMBtu. As discussed in the proposal preamble (88 FR 24868), the average fPM rate reported by the best performing 25% of sources was 0.0014 lb/MMBtu, lower than the 2012 UPL mean. The Agency also calculated the average value of the best performing 12% of sources expected to be subject to the final RTR provisions. Of the 296 EGUs assessed in the final rule, the EPA calculated the mean of the best performing 36 EGU (12% of 297) average fPM rates, yielding a rate of 0.0011 lb/MMBtu, almost two times less than the 2012 UPL mean.

Second, it is not clear in Figure 1 presented by commenters (and shown again below) if the MATS ICR and 2019 data are paired for each independent EGU (allowing an "apples to apples" comparison) or if the MATS ICR and 2019 data are each sorted by fPM rates independently. The later would be an inaccurate characterization to illustrate how fPM rates have changed since the original MATS rulemaking. However, if the former is true, the Agency notes that Figure 1 presented by commenters shows almost indistinguishable differences for approximately 33 EGUs in the MATS ICR and 2019 fPM rates, as these points are either overlapping or nearly touching. It is likely that these two values for these 33 EGUs are within measurement uncertainty, and therefore cannot be meaningfully discussed as different. Additionally, there appears to be EGUs presented in this figure that are not expected to be impacted by this rulemaking. For instance, the largest 2019 fPM rate presented in the Commenter's Figure 1 of approximately 0.057 lb/MMBtu is the average stack test value for Transalta Centralia Generation (3845_B_BW22, Washington), much larger than the initial standard of 0.030 lb/MMBtu. However, this unit at Transalta Centralia Generation is expected to retire in 2025 and therefore will not be subject to a lower fPM limit. Similarly, the next highest 2019 data point of 0.029 lb/MMBtu is from Duck Creek (6016_B_1, Illinois), which closed in 2019. The EPA does not believe such data points from EGUs closed or soon to be closing before the compliance timeframe, are relevant to be included in the fPM analysis or discussion.

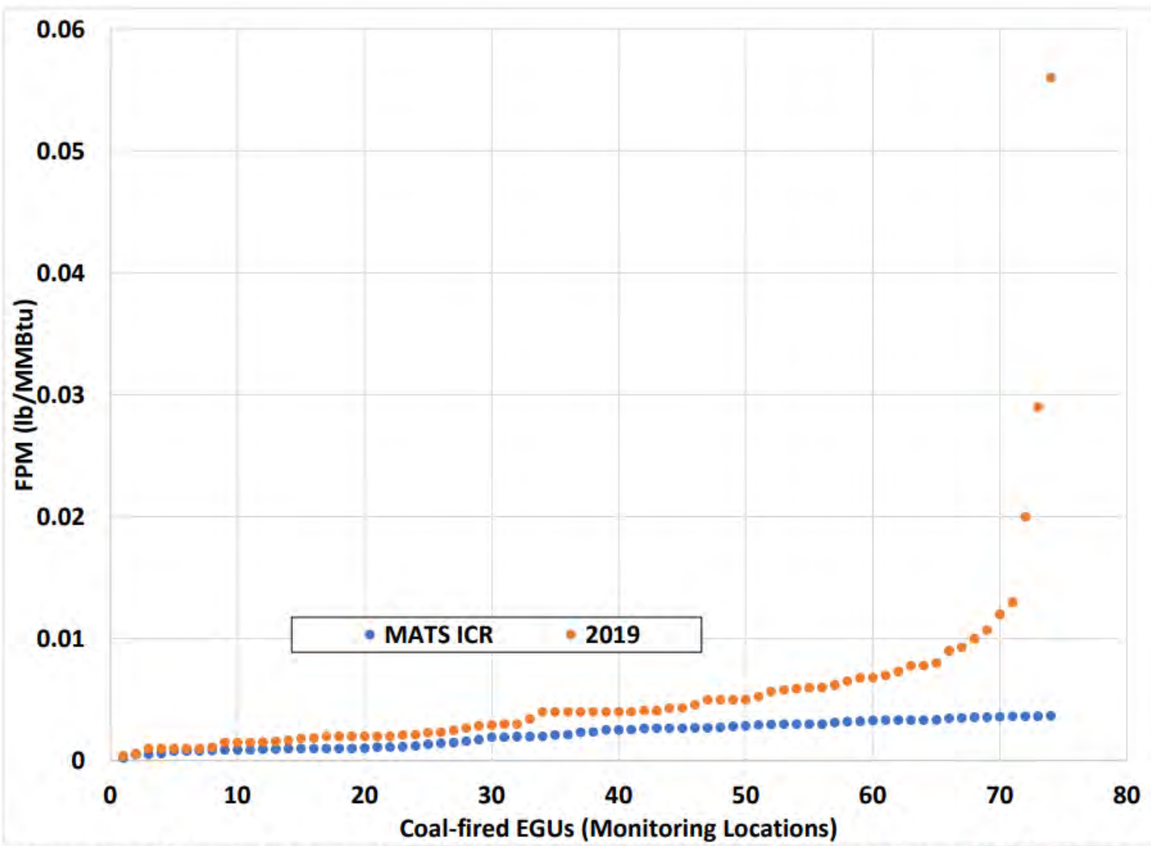


Figure 1. Comparisons of PM Emissions from ICR and 2019 for MACT Floor Units

Figure above captured from Nebraska Public Power District/Agora comments to the docket (Docket ID No. EPA-HQ-OAR-2018-0794-5911).

2.3.2 Merging PM CEMS and Stack Test Data

Comment 1: Commenters expressed concern that the EPA's database includes emissions reported from PM CEMS and performance tests that should be evaluated separately, not merged as one data set. Commenters explained that in contrast to the continuous measurements taken by

PM CEMS, indirectly through light scatter or beta attenuation, measurements taken via stack testing are direct measures calculated by the mass of PM and the volume of flue gas from which that mass of PM was sampled and are conducted under representative testing conditions. Commenters expressed that direct and indirect measurements of fPM merged together may lead to results that compromise the accuracy of the data set especially during periods of atypical operation. Commenters indicated that any unit using a PM CEMS to demonstrate compliance with the emissions limit also must conduct annual emissions measurements under steady-state conditions which are utilized in either an RCA or RRA, and that process or fuel related changes, even control equipment repairs or adjustments may have occurred since the last correlation that would not be fully captured in the response of the analyzer.

Commenters conveyed that data in the EPA's evaluation were predominantly stack testing fPM data since the majority of EGUs are using stack testing for compliance and this may bias the data. Commenters indicated that such data does not provide information across a unit's entire load range, including during startups, shutdowns, maintenance, and malfunction events all of which would be captured by a PM CEMS. Commenters recognized that by using a single point of reference or snapshot for most units in the dataset, the EPA has not addressed variability caused by meteorological conditions, load/market demand, unit outages, operating conditions, fuel composition, control device efficiency, and many other factors that greatly impact a unit's emission rate over a period of years. Commenters noted that exclusion of such data likely overstates the units that can demonstrate the more stringent limits on a continuous basis undercounting fPM upgrades or retrofits and project costs. Commenters communicated that if the EPA eliminates performance testing as a compliance option and moves to a PM CEMS only approach, the EPA should rely exclusively on PM CEMS data to set the fPM limit. Commenters noted that this decision would rectify concerns that PM CEMS data has a high bias as opposed to stack test data.

Response 1: The Agency recognizes the data from these two compliance demonstrations are different, including averaging over different time periods, continuous vs. "snapshot" observations, and direct vs. indirect measurements. However, the Agency disagrees with commenters that direct and indirect methods of measurement merged together compromises the accuracy of the results. The PM analysis is done on a unit-by-unit basis, meaning for each EGU the assessed fPM rates are only from one method of measurement. Most EGUs have not changed their compliance demonstration since promulgation of the original standards, and use of the recent fPM compliance data ensures that the Agency is assessing the most up to date compliance information available for each EGU. As numerous demonstration methods were allowed for the fPM standard, it would be inconsistent to weigh one method more than the others. Owners and operators are responsible for maintaining their PM CEMS, and if any process or fuel related change occuring since the last correlation alters the correlation, it is the owner or operator's responsibility to take action. Therefore, the Agency disagrees with commenters that stack test and PM CEMS emission data need to be evaluated separately.

Additionally, the Agency disagrees with commenters that the EPA has failed to address emission variability caused by a variety of factors. The EPA evaluated fPM rates based on compliance demonstrations for the final rule. Of 177 EGUs using stack testing, the average value of all evaluated historical average fPM data is 0.00512 lb/MMBtu (median=0.00397 lb/MMBtu).

Similarly, of the 113 EGUs using PM CEMS, the average value of the evaluated historical average fPM data is 0.0057 lb/MMBtu (median=0.00464 lb/MMBtu). While more EGUs currently use stack testing to demonstrate compliance, these results indicate there is no substantial difference in average fPM rates between compliance demonstrations.

Comment 2: Commenters were split on the EPA's suggestion to rely solely on PM CEMS data versus stack testing for demonstrating compliance with the proposed standard of 0.010 lb/MMBtu, yet some expressed concern that some PM CEMS may struggle to meet the EPA's guideline for average random error contribution to the PM CEMS tolerance to demonstrate compliance with a fPM emission limit of 0.006 lb/MMBtu or lower. However, they were clear on their request that the EPA use only stack test data or CEMS data to set the standard. Commenters stated that courts have recognized that the EPA cannot develop an emission standard based on data derived using one method and require facilities to demonstrate compliance with that standard using another method citing *Portland Cement v. Ruckelshaus,* 486 F.2d 375 (D.C. 1973); *see also Nat'l Lime Ass 'n v. EPA*, 627 F.2d 416, 452-53 (D.C. Cir. 1980); *Amoco Oil Co. v. EPA*, 501 F.2d 722, 743 (D.C. Cir. 1974).

Response 2: The EPA agrees with commenters that some PM CEMS may struggle to meet instrument specifications at the more stringent fPM limit of 0.006 lb/MMBtu and points to the rationale for the final fPM standards in section IV.D of the preamble. The Agency disagrees with some commenters that not all fPM compliance data should be used to develop a fPM emission standard. As several methods were allowed for compliance purposes, it would be inconsistent to prioritize some data over others. Since the proposal, the use of average fPM rates have also been incorporated into the final analysis for PM upgrade cost assumptions, which reflect variability and number of data points congruent with compliance methods.

In *Portland Cement v. Ruckelshaus*, the court recognized that it is incumbent on EPA to "explain the discrepancy" where sampling techniques differ from procedures for ascertaining compliance. 486 F.2d at 397. While *Portland Cement* recognized such a difference can raise questions, commenters are incorrect to claim that the EPA cannot utilize a compliance method that differs from the sampling technique used to establish it. Whereas the commenter cited to cases which discussed potential enforcement concerns, *see Nat'l Lime Ass 'n v. EPA*, 627 F.2d 416, 452-53 (D.C. Cir. 1980); *Amoco Oil Co. v. EPA*, 501 F.2d 722, 743 (D.C. Cir. 1974), the EPA reasonably believes that PM CEMS will improve enforcement. As the EPA has explained elsewhere throughout this record, PM CEMS provide owners and operators, regulators, and the public with a cost-effective direct and continuous measurement of the pollutant of concern, thus allowing for more effective enforcement than quarterly stack testing.

2.3.3 PM Control Assumptions

Comment 1: Commenters suggested that the EPA's evaluation failed to take into consideration different control configurations, particularly the variation in PM removal efficiencies. Some commenters explained their control configuration captures and removes PM from the flue gas path primarily by the existing ESPs, and the wet FGD system downstream of the ESPs will also capture some of the PM that makes it through the ESPs. They stated the effectiveness of the existing ESPs and wet FGD system to control PM emissions and demonstrate compliance with the proposed fPM emission limit of 0.010 lb/MMBtu will be negligible under even the best operating scenarios. Commenters expressed concern that the EPA's reliance on existing data does not appear to have adequately considered the impact of the degradation in the effectiveness of emission control devices and may have overestimated affected units' ability to comply with the proposed limit. Commenters specifically mentioned units with the same flue gas path and air pollution control equipment in series, yet the units result in significant differences in fPM reduction capabilities. Commenters indicated that some PM control technologies, such as, hotside ESPs, inherently have higher PM emissions. Commenters noted that depending on the coal combusted, units that utilize hydrated lime as a control technology for minimizing HAP, like Hg and sulfuric acid, inherently have higher PM emissions. Commenters noted that wet FGD may also result in higher PM emissions in particular, higher variability in fPM emission rates because wet FGD can either add particulate from mist eliminators or remove additional particulate. Commenters recognized that because control devices perform at their optimum when operating at full-load, steady state conditions, and additional transient operation will negatively affect their removal rates. Commenters stated that while PM emissions may be lower during low-load periods, there generally is particulate layout in the duct work during such periods and, as units ramp to higher loads, the particulate re-entrains, potentially leading to higher emissions, in addition at low loads, wet FGD mist eliminators operate at reduced efficiency and wet FGD slurry carryover can increase PM emissions at reduced loads. Commenters requested that the EPA factor in specific types of control configurations. Commenters noted that if the fPM limit were lowered to 0.006 lb/MMBtu instead of 0.010 lb/MMBtu, units with ESPs may be required to add FFs. They also stated this will leave virtually no margin to maintain compliance in the absence of significant upgrades to the emission control device(s) performance, which would not be cost effective for units with a remaining service life of less than six years.

Commenters noted that the highest emitting units have the oldest equipment, particularly those with scrubbers and ESPs, and that replacement or improvements to degraded controls should allow these units to meet the proposed 0.010 lb/MMBtu fPM standard.

Response 1: The EPA acknowledges these comments submitted about the variation of PM removal efficiencies based on control configuration. The EPA evaluated different control configurations for the proposal in Table 3 in the 2023 Technical Memo (Docket ID No. EPA-HQ-OAR-2018-0794-5789). This review found that EGUs with wet scrubbers only are associated with the largest fPM rates, and that other control configurations have lower fPM rates on average. The EPA also acknowledges that some control configurations have inherently higher PM emissions and that some downstream control devices (dry sorbent injection, activated carbon injects, *etc.*) can add particulate loading to the flue gas stream. But, as the EPA has noted several times, 93 percent of sources operating by the compliance period have demonstrated an ability to comply with the more stringent fPM limit of 0.010 lb/MMBtu. Those EGUs include units with a variety of downstream control configurations, including hotside ESPs, dry sorbent injection, and activated carbon injection, *etc*.

The Agency disagrees with commenters that the reliance on historical fPM compliance data does not consider the impact of degradation of the effectiveness of emission control devices that may overestimate unit's ability to comply with the proposed limit. However, the Agency recognizes that EGUs that may have demonstrated an ability to meet a lower fPM rate in the past may not do so consistently. For this reason, the fPM analysis assumptions have been updated to assess both the lowest achieved fPM rate (defined as the lowest quarter's 99th percentile) and average of all evaluated fPM data when estimating PM upgrades. The average fPM rate will account for unit variability as well as some degradation of emission control effectiveness. In cases where the EGU has demonstrated an ability to meet a lower rate but does not do so on average, the Agency has updated PM assumptions based on the PM controls at the facility. If the EGU already has a fabric filter, we assume increased bag frequency change-out (unit specific) or an O&M cost of $100,000/year for EGUs without fabric filters. These assumptions are described in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category," and unit-specific cost assumptions are provided as an excel attachment to the memo.

Related to the comment about EGUs with ESPs needing to install FFs to meet a more stringent limit of 0.006 lb/MMBtu, this comment is not relevant as the Agency did not finalize this standard and therefore does not require a response.

Lastly, the Agency agrees with commenters that usually the highest emitting EGUs have the oldest equipment, and that improvements found to be cheaper than assumed at the original MATS rulemaking will allow EGUs to meet a limit of 0.010 lb/MMBtu.

2.4 Compliance Demonstration

2.4.1 Removal of PM LEE

Comment 1: Commenters stated that if there are to be changes to the numerical emission limit, then there should not be a change to the compliance demonstration method or to the frequency of testing to meet a numerical limit that is only two-thirds of the fPM emission rate that defined a LEE under the previous rule.

The commenters said that sources that are not "low-emitting sources" and required to install a PM CEMS are subject to more stringent requirements associated with the development of the PM CEMS correlation curve (see Performance Standard 11, Section 13.2), which are exceptionally challenging to develop irrespective of the source emitting status.

Commenters stated that this is especially true for EGUs that are equipped with FF PM control devices (baghouses) or equipped with an ESP and a FGD. Baghouses are the most effective fPM control devices available and typically an FGD will control an additional 70% of the fPM remaining after the exhaust gas passes through the ESP, which alone removes 98% - 99% of the fPM. The commenters said that so long as there is not a physical or permitted capability to allow discretionary bypass of the baghouse or ESP/FGD combination, there is no need to require continuous fPM monitoring. With these control equipment devices, which result in extremely low fPM emissions, in place, a requirement to site, procure, install, certify, operate and maintain, quality assure and maintain a data acquisition and handling system to record and maintain records is unnecessary and only serves to increase the cost of the demonstration of compliance with no demonstrated monetized benefit.

Commenters stated that there is no need to either require emissions measurement more frequently than the current fPM LEE schedule or require the use emissions measurement methods for units equipped with these fPM emissions control equipment devices. The commenters said that units with these devices would be required to meet a fPM limit that is 33% lower than the current fPM LEE limit of 0.015 lb./MMBtu. They said, in practice, other currently installed monitoring devices are used as an indicator of fPM emissions control performance (*e.g.,* opacity monitor for units installed with a baghouse or dry FGD, mist eliminator pressure drop for units installed with a wet FGD), which also reduces the efficacy of the proposed requirements. They said that for context, to qualify as a fPM LEE, the source had to consistently meet a limit that was only 50% of the fPM limit finalized in the rule. They said that moreover, a change in the fPM emission limit from 0.030 to 0.010 (or lower) lb/MMBtu would likely disqualify a source from realizing "low-emitting source" status without any change in source operating practices, procedures, or emission control device performance.

Commenters conveyed their concern over the proposed limit of 0.010 lb/MMBtu fPM due to the EPA rejecting the 0.015 lb/MMBtu limit which is 50% of the current standard and the qualifying emission rate for the LEE program. Commenters recognized a significant factor regarding the reduction in the proposed fPM surrogate to 0.010 lb/MMBtu, or the more stringent 0.006 lb/MMBtu limit; they stated that the EPA is not just revising the numerical value, but also changing both the compliance determination technique and the averaging period. Commenters expressed that the EPA is essentially penalizing sources that have consistently met the LEE limit of the 2012 MATS Final Rule (0.015 lb/MMBtu) by eliminating the reward of testing once every three years after a lengthy demonstration of the ability to meet that limit. Commenters recognized that EGU's demonstrated exemplary agility in complying with the original fPM emissions limit and continued compliance over the past eight (8) years.

Commenters believe lowering the emissions limit closer to the BACT removal efficiency ratings for new EGU's, without health benefit justification, will only subject existing EGU's to unnecessary regulatory scrutiny without any health benefit gain. They stated that the LEE limit allowed units; especially, those that are cycling or load following as the grid integrates more renewable resources, some additional flexibility to operate. Commenters are concerned about increased EGU operation and maintenance (O&M) costs during high inflationary periods on account of the undue financial impacts that will impact utility customers again with little to no health benefits to the public. Commenters stated that qualifying LEE generators or low non-Hg HAP emitters are the most impacted as they are smaller power producers with small customer bases from which to recover regulatory imposed financial burdens.

Response 1: The EPA acknowledges and thanks commenters for providing these comments. In requiring PM CEMS, the Agency believes owners and operators will be able to use the real-time data to improve the performance of their EGUs. Additionally, the standard using PM CEMS is a 30-day rolling average, a longer averaging period than the average over three stack test runs conducted quarterly or every 36 calendar months. We have further discussed our rationale for the final emission standards in section IV.D of the preamble.

Comment 2: Commenters recommended that the EPA continue to recognize LEE status for EGUs that generate less than 300 MW. Commenters suggested grandfathering the current LEE provision to protect small EGUs and their small customer base from undue financial impacts. They stated if there are to be changes to the numerical limit, then there should not be a change to the compliance demonstration method or to the frequency of testing to meet a numerical limit that is only one-third less than the fPM emission rate that defined a LEE under the 2012 MATS Final Rule.

Response 2: The Agency estimates there are approximately 67 EGUs subject to a lower fPM limit that have a generating capacity less than 300 MW, 19 of which are currently PM LEE. Of the 67 EGUs, the Agency estimates that only 7 would need to invest in bag type upgrades or increased bag changeout frequency to achieve a fPM rate of 0.010 lb/MMBtu. The annualized costs for such upgrades for these units ranges from $10,800/year to $55,600/year. The Agency believes such costs are reasonable.

2.4.2 Use of PM CEMS

Comment 1: A few commenters recommended that multi-metal CEMS be an allowed alternative for demonstrating compliance with the 2023 Proposal's final rule. Commenters noted that measurement of individual metals is far more meaningful with regards to the intent of the CAA than the proposed fPM surrogate monitoring. Commenters recommendation is based on the proven performance and commercial availability of multi-metal CEMS to demonstrate compliance with HAP metal emission limits as well as an alternative to PM and Hg CEMS. They also stated the use of multi-metal CEMS methods would allow all of the urban HAP metals including Hg and all phases to be continuously monitored with a single CEMS. Commenters stated that the EPA's new total PM standard is a poor surrogate for fPM, which is a weak surrogate at best for HAP metals, particularly when considering such HAP metals as Se.

Response 1: The filterable PM surrogate standard has been previously explained and justified in the original MATS rulemaking. As allowed by the NESHAP general provisions, an owner or operator interested in using multi-metals CEMS or other continuous techniques to demonstrate compliance with equivalent or more stringent total or individual metals limits may request permission from the Administrator to seek an alternative test method under the provisions of 40 CFR part 63.7(f) and use the alternative metals limits as provided in the rule.

Comment 2: Some commenters participated in a jointly funded effort to investigate PM CEMS and stack testing costs for the purpose of the current rulemaking. Commenters obtained actual cost data from various sources for PM CEMS installation, certification, ongoing quality assurance testing, and operating and maintenance costs, as well as actual cost data provided by various sources and stack test vendors to assess stack testing costs. They concluded that the Agency's justification for the requirement to use PM CEMS as the only compliance determination method in the 2023 Proposal is fundamentally flawed. Commenters noted the current fPM compliance options of periodic emissions testing, CPMS or a PM CEMS are achieving the goal of reducing potential impacts to human health and the environment; adding PM CEMS requirements to all EGUs will make little difference for overall air quality while substantially increasing the costs that must be borne by consumers. Commenters indicated that the Agency has significantly understated PM CEMS costs and significantly overstated ongoing stack test costs for units utilizing the quarterly stack testing and LEE compliance options. Commenters suggested the Agency allow sources to comply with either the quarterly stack testing, LEE or PM CEMS compliance options when finalizing the 2023 Proposal.

Response 2: The EPA disagrees with the commenters' suggestion that the selection of the rule's compliance determination method is fundamentally flawed. The EPA selects compliance methodology based on many factors, with the application and availability of continuous emissions monitoring such as PM CEMS, being a chief concern. Periodic testing provides emissions information only during discrete periods of time when testing occurs; it cannot provide continuous emissions information like PM CEMS can. PM CPMS provides parameter, not emissions data, on a continuous basis, as opposed to PM CEMS, which provide continuous emissions data. Note that source owners or operators whose EGUs currently rely on PM CPMS may be able to recast those instruments as PM CEMS and provide continuous filterable PM emissions data for little additional cost. The EPA disagrees that instrumental costs are significantly understated and that quarterly testing costs are significantly overstated. As a reminder, the EPA is not obligated to choose the most cost-efficient manner for compliance demonstrations, even though cost can be an important consideration; rather, the EPA seeks to find appropriate monitoring that is most suitable for compliance demonstration. The costs for instrument use and quarterly testing are derived from averages provided by commenters and are discussed and summarized in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* memo, available in the docket and in section IV.D of the preamble.

2.5 Technical feasibility

2.5.1 General

Comment 1: Commenters suggested that the EPA's evaluation is flawed and some coal-fired EGUs may not be able to achieve compliance with the proposed fPM standard of 0.010 lb/MMBtu on a continuous basis. Commenters communicated that the EPA's reliance on the 2023 Technology Review memo is problematic for several reasons, and they are concerned that the EPA is overstating the units that will be able to meet the proposed standard. Commenters requested that the EPA describe how, if most of the affected units are already achieving lower emission rates, requiring the remaining units to meet the lower rate is "necessary." They are of the opinion that the EPA should retain the current fPM emission standard of 0.030 lb/MMBtu based on previous analyses performed by the EPA which concluded there are no new technologies or changes in technologies that reduce PM or non-Hg metals. Commenters further noted that although the EPA claims existing coal-fired EGUs have demonstrated that they can achieve an emission rate of 0.010 lb/MMBtu or lower does not necessarily mean that those EGUs can continuously achieve compliance with the emission rates.

Commenters provided that other factors such as EGUs' operational limitations could hinder the ability of some coal-fired EGUs to continuously comply with the proposed fPM standard. Commenters mentioned operational factors, such as, cleaning frequency, operational duration, and filter change out frequency may impact the performance of controls and an EGU's ability to comply with the proposed limit. Commenters noted that some units may be able to achieve a rate of 0.010 lb/MMBtu during shoulder months, yet they may not be able to continuously meet that limit during peak load conditions when they cannot do off-power rapping or maintenance and cleaning of ESPs to remove buildup on the ESPs' wires and plates. Commenters provided examples, such as, if an ESP must be taken off-line for cleaning which requires 24 to 48 hours for cooling before temperatures are low enough for maintenance personnel to safely enter the ESP to perform repairs. Commenters stated that at a minimum, vacuuming may be required of the ESP inlet and outlet ducts, along with any hoppers that have high levels, and some ESPs may require sandblasting to remove problematic buildup on wires and panels. Commenters expressed concern that the EPA has not evaluated the technological feasibility or safe operating conditions of ESPs. They stated that ESPs cannot safely be engaged at first firing of coal due to a minimum operation temperature necessary for their safe and reliable operation without risking equipment damage, fire, and/or explosion. Commenters indicated that unless there are additional outages scheduled for such maintenance, the units may be unable to maintain compliance with the proposed 0.010 lb/MMBtu limit. Commenters noted that during the summer, most units operate at base load and run at high-capacity factors and may find it difficult to maintain optimal operation of control technologies during peak conditions. Commenters stated capacity factors of coal-fired EGUs are now typically lower during the day when solar and wind are available, but the demand for coal-fired EGUs is greater at night when renewable generation is unavailable. Commenters indicated that the EPA runs the risk of eliminating the necessary compliance margin to account for operational and fuel variability and thus significantly restricting a unit's operational flexibility with the proposed limit.

These commenters explained that even with ESPs, FFs and reagent injection systems; such as, a powdered activated carbon injection system for the removal of Hg in place, not all EGUs have demonstrated continuous compliance with the proposed 0.010 lb/MMBtu fPM limit, much less the EPA's more stringent alternative fPM limit of 0.006 lb/MMBtu put forward as a surrogate for HAP metals. They expressed concern with a standard of 0.010 lb/MMBtu, particularly for ESP controlled units challenged to comply during typical cold starts and may find it impossible to comply during atypical cold starts, or if a unit is forced to attempt more than one cold start within a 30-boiler operating day window. Commenters expressed concern that additional reductions in the emissions of non-Hg metals regulated under the 2012 MATS Final Rule would not be realized if the surrogate fPM emission limit is revised to 0.006 lb/MMBtu or lower for their units and other EGUs with similar emissions control devices.

Commenters suggested plantwide averaging may provide additional compliance flexibility for companies by not requiring every unit to achieve the proposed standard on its own.

Response 1: The Agency disagrees with commenters that all EGUs need to have previously demonstrated continuous compliance with the proposed 0.010 lb/MMBtu standard or the more stringent 0.006 lb/MMBtu standard in order to establish an emission limit. The review of all historical fPM CEMS compliance data, collected for the most part over third quarter operation, which is believed to be a period of maximum load operation and is discussed in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category" and accompanying attached Python code plotting the additional fPM compliance data available in the docket, found several EGUs have continuously met these lower fPM limits. Additionally, there was no regulatory reason for EGUs to operate and report emissions less than the limit (0.030 lb/MMBtu), unless their normal operation, coupled with their normal control device operation, resulted in emissions lower that the regulatory limit. Furthermore, the 30-boiler operating day averaging period allows for operational and fuel variability and provides significant flexibility for owners to account for equipment malfunctions and issues and comply with a lower fPM standard. For instance, as shown in section 4 of the 2024 Technical Memo, hourly PM CEMS data (excluding startup, shutdown, and malfunction periods) for Case Study 1 range from near-zero to 1.33 lb/MMBtu from one unit at the facility. The 30-boiler operating day averages for this unit range from 0.001 to 0.015 lb/MMBtu, considerably smoothing out the variable hourly averages. As mentioned above, there was no regulatory reason for this EGU to operate and report emissions less than the limit. In addition, in response to concerns about operational factors, as described in 63.10010(i)(4), data from PM CEMS during any scheduled maintenance are excluded when determining compliance. The EPA agrees with commenters that plantwide averaging is another compliance flexibility available to owners and operators.

Comment 2: Commenters suggested the Agency take into consideration the many variables affecting fuel characteristics. Commenters stated the availability of coal is limited to certain regions and, as a result, the characteristics of coal vary depending on location and may impact the unit's ability to demonstrate continuous compliance with the proposed fPM standard. Commenters noted that the ash content of the coal being fired may impact the ability of units to comply with the proposed limit, regardless of the effectiveness of the control technologies in place. Commenters conveyed that using fuel oil for startup and stabilization may impact the ability of units to comply with the proposed limit due to decreases in the removal effectiveness of the ESPs for a short period of time until enough coal is introduced so that the amount of coal ash in the combustion process has scoured the coating of the collecting plates and wires. They expressed concern that the costs associated with adding an FF to well-controlled units cannot be justified simply to address issues which arise rarely and for a short period of time.

Response 2: The Agency thanks commenters for providing these comments and agrees fuel characteristics can impact fPM emissions. Using fuel oil during periods of startup for short durations will likely raise fPM emissions for a short period of time, and the 30-day rolling average period will lessen its impact. The Agency previously evaluated the impact of fuel characteristics on fPM emission rates in the 2023 Technical Memo (Docket ID No. EPA-HQ-OAR-2018-0794-5789). This review found for the majority of EGUs burning either bituminous or subbituminous on average have lowest achieved fPM rates below the most stringent standard considered, with larger 95th percentiles of approximately 0.0106 and 0.0155 lb/MMBtu, respectively. These larger fPM values are found for only a few EGUs and are not surprising as there was little incentive towards reducing fPM rates already 50-65% below the standard (and outside the industry compliance margin).

Comment 3: Commenters suggested that the age and retirement date of affected units with ESPs should be considered. If an affected unit is planning to retire soon after the effective date of the proposal, installation of FFs would not be a cost-effective choice for the plant owner, who might choose to shut down the plant early and unnecessarily stress electricity generation supply or capacity. The commenters said that to maximize the flexibility of existing coal-fired units, maintain grid flexibility and to provide flexibility in the electric transmission system, the 0.010 lb/MMBtu standard should be preferred.

Response 3: The Agency agrees that age and retirement date of affected EGUs should be considered. Of EGUs not meeting the 0.010 lb/MMBtu proposed standard, 14 have announced retirement dates spanning from 2030 to 2042, half of which only have an ESP for controlling fPM (Labadie, Roxboro, Mayo, and Jim Bridger). To meet a 0.010 lb/MMBtu limit, the EPA estimates ESP upgrades would be required for Labadie, Roxboro, and Mayo, while Jim Bridger only requires O&M at $100,000/year. Therefore, installation of FF would not be required at these EGUs to meet a 0.010 lb/MMBtu standard.

Comment 4: Commenters stated that the EPA must also investigate whether there are sufficient vendors to perform fPM upgrade projects or install new fPM controls. The commenters said that NRECA's Technical Report estimates that 26 units will be required to upgrade ESPs if the EPA sets the fPM emissions limit at 0.010 lb/MMBtu. This number grows substantially to 52 ESP-controlled units that would need to retrofit to a FF if the limit falls to 0.006 lb/MMBtu. Commenters said they believe there are only about 4 active vendors in the United States market.

Response 4: The EPA thanks commenters for providing these comments. In this final rule, the EPA estimates 2 EGUs may require a FF install, 11 may require ESP upgrades, 10 need either a bag type upgrade or increased changeout frequency, and 10 need O&M to meet the final fPM limit of 0.010 lb/MMBtu. The compliance deadline is three years after publication in the Federal Register, and owners and operators may request an additional year for installation of controls if necessary.

2.5.2 Intersection with Other Power Sector Rules

Comment 1: Commenters identified future regulations such as the Interstate Transport Rules and Regional Haze SIPS that may result in installation of DSI or SDA technologies to reduce SO_2 emissions are expected to increase inlet PM loading to the FFs due to more hydrated lime and reaction byproducts placing those units at risk of not being able to meet the proposed fPM standard of 0.010 lb/MMBtu. Commenters indicated that some units may inject sodium or calcium-based products upstream of the PM collection equipment which increases PM loading.

Commenters also requested that the EPA maximize all regulatory flexibilities at the Agency's disposal to align the requirements of the 2023 Proposal and the Proposed CAA section 111(d) Guidelines. The Proposed CAA section 111(d) Guidelines are part of an unprecedented rulemaking package that will transform the electric sector and will come at a similarly unprecedented cost that will be borne by individual residents and businesses. Commenters suggested, rather than exacerbate these costs and strain system reliability by imposing serial outages, the EPA should utilize its substantial discretion under CAA section 112 and decline to revise fPM standards for "long-term" coal units.

Commenters stated that CAA section 111(d)(6) affords the EPA significant discretion in determining whether to revise standards for sources within a source category: "The Administrator shall review, and revise as necessary…" (42 U.S.C. § 7412(d)(6)). Commenters urged the EPA to exercise this discretion and decline to establish fPM requirements for units designated as "long term" units in CAA section 111(d) state plans. Commenters stated that the 2023 Proposal itself acknowledges the breadth of the EPA's discretion. They said the EPA has proposed not to revise multiple standards established by the MATS—the acid gas standards for coal-fired units, the standards for continental and non-continental liquid oil-fired units, and the standards for existing IGCC units. The commenters said, notably, this demonstrates that the EPA is able to parse the need to revise standards for some pollutants and not others, within a single category of sources.

Commenters stated that likewise, it is well within the EPA's discretion to recognize coal-fired electric generating units designated as long-term units in CAA section 111(d) state plans and decline to revise fPM standards for these units—similar to its recognition of "non-continental units." They said, importantly, the EPA intends for states to designate units as long-term units no later than 2026 and that this timeline ensures that existing coal units that are not designated as long-term units would be subject to compliance with any revised fPM standard by the applicable statutory deadline.

Response 1: The EPA acknowledges and thanks commenters for these comments. Regarding aligning requirements of this rulemaking with the 111(d) Proposed Emission Guidelines, CAA section 112 specifies different requirements for compliance. Specifically, as defined in CAA section 112(i)(3)(A) "…the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of the standard." The Agency has not previously subcategorized based on retirements under CAA section 112, and do not find it appropriate to do so at this time.

2.6 Costs

2.6.1 General

Comment 1: Commenters suggested that the EPA's justification relies heavily on the Agency's estimation of lower than anticipated costs of control technology, significantly underestimating the 2023 Proposal's feasibility and cost of compliance. Commenters advocated that lower costs are neither developments in practices, processes, or control technologies as referenced in CAA section 112(d)(6), nor do lower costs equate to being cost-effective. They noted that the EPA's cost estimates seem to be substantial underestimates. Commenters felt that the EPA provides inaccurate cost estimates for tightening of the current fPM limitations and adequate consideration to the cost impacts of the 2023 Proposal have not been given, particularly for small power generation operators. They recognized that the EPA is required to factor in costs for the RTR analysis; however, in this case, commenters provided that the 2023 Proposal's cost estimates fail to account for all of the fPM upgrades and/or installations required for compliance with the new proposed lower limit. Commenters stated the EPA's cost study was deficient in terms of the number of ESP equipped units required to retrofit improvements, the capital cost assigned for the most significant ESP improvements, improvements in FF operation and maintenance, FF retrofit, and estimates of $/ton cost effectiveness incurred.

Commenters also stated that the EPA's deflated and unrepresentative fPM baseline is not accurate and therefore it is not possible to project the number of units that will need upgrades which lead to cost per ton underestimates that erode the EPA's overall assumption that the 2023 Proposal is cost effective. Specifically, commenters said the EPA's estimate that only 20 units are likely to incur any costs to meet the new standard is incorrect. As an initial matter, it is fatuous to conclude that a unit that happened to emit in a single quarter out of the last 20 quarters at 0.010 lb/MMBtu or less will not be required to do anything to meet the proposed revised standard. The commenters referred to a chart of data and said that even a unit that the EPA says has a "baseline fPM rate" of 0.086 lb/MMBtu was actually emitting more than 0.010 lb/MMBtu in 10 out of 20 quarters, so clearly, such a unit would need to upgrade control equipment to meet the proposed standard consistently.

Other commenters noted that the proposed changes associated with the 2023 Proposal requirements will cause inconsistency with existing permitting authorities' boilerplate special condition language and guidance documents which will require revisions to prevent regulatory overlap. They expressed concern that the proposed standards will require more time and more resources for regulatory agencies to implement, particularly agencies impacted due to the number of coal-fired units in their state. If the proposed standards are adopted, commenters felt the EPA should consider these impacts and adjust grant funding or other resources to facilitate implementation.

Commenters agreed, as the EPA points out, much of the fleet will not incur such high substantial additional costs; instead, the tens of millions of dollars of annual compliance costs will fall disproportionately on a few facilities. They brought up Colstrip in particular and felt the EPA does not adequately justify its proposal of forcing a few facilities to incur massive compliance costs, only to incrementally reduce emissions that have already been reduced to a level which the EPA agrees poses no danger to the environment or public health. Commenters further recognized setting the standard at 0.006 lb/MMBtu would require additional investment in new or significant upgrades to existing control technology that could both extend the life of units that would have otherwise been retired and complicate other retirement plans by requiring investments in controls in advance of the 2030 timelines contemplated in other rules.

Commenters brought up specific concerns for certain EGUs in their comments:

- Commenters assumed capital costs of at least $350,000,000, and annualized costs of $57,000,000, based on the working assumption that Reheat FF is the most viable technology Colstrip would deploy to comply with the 2023 Proposal.
- The commenters said that the EPA also underestimates the cost of such major ESP upgrades and even putting these major flaws aside, based on the EPA's own identification of units that would require major controls, and assuming the cost of ESP rebuilds at $100/kW, the capital cost of these controls would range from $41.7 million (for the D B Wilson EGU) to $148 million (for each of the Colstrip units).
- Commenters stated that based on their analysis of the Young Station units, commenters asked the EPA to reconsider setting an emissions rate that will require such substantial and costly ESP upgrades. The commenters said that the EPA should weigh the lack of any meaningful health risk posed by HAP emissions from our units with the hefty cost burden that the projects place on a nonprofit entity and, ultimately, on rural and small communities in the form of energy costs.

Commenters stated that in the proposed 0.010 lb/MMBtu limit for fPM, the EPA assumes that approximately eight existing ESPs may need physical equipment upgrades to comply with the proposed fPM emission standard. However, certain wet scrubbed units may need to install FF to meet the 0.010 lb/MMBtu limit. They said that the EPA assumes that to reduce fPM to 0.006 lb/MMBtu or below, FFs would be required and that 65 units would need to install a new FF or modify an existing FF to meet the lower revised fPM emission limit. The commenters said that if the fPM limit were lowered to 0.006 lb/MMBtu instead of 0.010 lb/MMBtu, units with ESPs may be required to add FFs.

Commenters referenced a recently completed analysis by Andover Technology Partners on the feasibility and costs of complying with lower emission limits, which found "the potential for compliance with lower PM, Hg, and HCl emission standards than in the proposed rule (https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.)." The commenters said Andover Technology Partners found that the cost to comply with an emission standard of 0.006 lb/MMBtu, (the more stringent alternative considered by the EPA in the 2023 Proposal), on a fleetwide basis is significantly less than the cost estimated by the EPA. Andover Technology Partners attributes this difference "to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu." *Id*. The commenters stated that the EPA should consider this new information and adjust its final standards as needed for fPM.

Commenters stated that an fPM emission limit of 0.006 lb/MMBtu would be particularly cost-effective and achievable at a very low and reasonable total cost, particularly when considered in the context of the power sector. They said that the 2023 ATP Assessment finds that EGUs could comply with this limit at an annual cost of about $442 million, while the EPA estimates the annual costs would be $633 million. The commenters said that while the EPA likely overestimates the cost of achieving this standard due to overestimating the number of baghouses that will need to be installed, even an annual cost of $633 million is reasonable in the context of the power sector, which can easily absorb that cost while continuing to provide affordable and reliable power. They said indeed, these costs would be a small fraction of the cost of the original MATS rule (projected and actual).

A few commenters stated that it is not surprising that the EPA's projected annual compliance costs were miniscule within the context of the power sector as a whole; equivalent, for example, to only 0.2% of 2019 total retail electricity sales (the lowest sales figure since 2000) considering 91% of existing EGUs have demonstrated an emission rate of 0.010 lb/MMBtu or lower.

Commenters stated that these costs should be considered in the context of the power sector, and even the EPA's likely overestimated cost would represent only about 0.26% of power sector total expenditures in 2019 ($242.9 billion) or about 0.16% of 2019 revenues ($401.738 billion). They asserted that while the power sector can absorb much larger costs, it is clear that the costs associated with an fPM standard of 0.006 lb/MMBtu are very small compared to power sector total expenditures, capital expenditures, and revenues—and well within the range of historic variability in total expenditures—and therefore can be absorbed without preventing the power sector from serving its function.

Response 1: We disagree with commenters that lower costs are neither developments in practices, processes, or control technologies as referenced in CAA section 112(d)(6), nor do lower costs equate to being cost-effective. As stated in the 2023 Proposal, a development may include "any significant changes in the cost (including cost effectiveness) of applying controls (including controls the EPA considered during the development of the original MACT standards).” 88 FR 24863 (April 24, 2023). The EPA responds to comments on underestimated costs in section IV.C.1 of the preamble.

We also disagree with commenters that using the lowest demonstrated fPM rate is not useful to estimate which EGUs may need to upgrade PM controls. We recognize that EGUs may be capable of meeting lower emission rates, but may not consistently perform at such low emission rates. As such, the analysis has been updated to use the average of all quarterly data reviewed or the lowest achievable fPM rate (lowest quarter’s 99^{th} percentile) to identify EGUs requiring improvements to PM controls. Additional details of the revised PM analysis are discussed in the 2024 Technical Memo entitled “2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category.”

Regarding comments that the proposed changes will cause inconsistency with existing permitting authorities’ boilerplate special condition language and guidance documents, EPA routinely revises its regulations due to statutorily required reviews.

Regarding comments that costs of annual compliance costs will fall disproportionately on a few facilities, the EPA points out that the fleet has been able to “over comply” with the existing fPM standard due to the very high PM control effectiveness of well-performing ESPs and FFs. However, the performance of a few units lags well behind the vast majority of the fleet. For instance, Colstrip is the highest emitting EGU the EPA assessed and the only facility that the EPA is aware of not using the most modern PM controls (*i.e.,* ESP or FF), and instead using a venturi wet scrubber as the only means for fPM controls. In addition, to the comment that emissions are already at a level that does not pose a danger to the environment or public health, as well as emissions will only be incrementally reduced by this rule, the EPA’s finding that there is an ample margin of safety under the residual risk review in no way interferes with the EPA’s obligation to require more stringent standards under the technology review where developments warrant such standards. Indeed, the technology review required in CAA section 112(d)(6) further mandates that the EPA continually reassess standards to determine if additional reductions can be obtained, without evaluating the specific risk associated with the HAP emissions that would be reduced.

Regarding the comments that EPA overestimated costs of compliance, the Agency has reviewed the additional information the commenters referenced and agrees with the commenters that ESPs are able to achieve greater fPM emission reductions at lower costs than assumed at proposal. We have lowered the costs of some ESP upgrades and increased the collection efficiencies, as shown in Table 3 of the 2024 Technical Memo. The impact of these updates to the ESP assumptions is a reduced need for EGUs to install a FF to meet a fPM limit of 0.006 lb/MMBtu, which lowers annual costs to approximately $400 MM. However, as described in the final rule and throughout this document, the EPA is finalizing a fPM limit of 0.010 lb/MMBtu as this is the lowest possible fPM limit utilizing PM CEMS.

As stated in Chapter 1 above, the EPA requested comment on whether EGUs should be able to continue to use quarterly emissions testing past the proposed compliance date for a certain period of time or until EGU retirement, whichever occurs first, provided the EGU is on an enforceable schedule for ceasing coal- or oil-fired operation; and on what would qualify as an enforceable schedule. The EPA address comments on this topic in Chapter 3 of this document.

We agree with commenters that the overall costs borne by the power sector are small compared to its revenue. The rationale for the final emission standards is provided in section IV.D of the preamble.

Comment 2: Commenters stated that while the EPA's estimates for the costs of most control upgrades are generally reasonable (*e.g.,* minor and typical ESP upgrades; FF bag replacements; FF replacements), commenters believed the EPA has substantially underestimated the cost of the control upgrades that would be required for most of the 20 units that the EPA estimates would have to take action to meet the proposed standard of 0.010 lb/MMBtu (*i.e.,* ESP rebuild). The commenters said that the EPA estimated an ESP rebuild would cost $75-$100/kW. They said the NRECA technical evaluation (EPA-HQ-OAR-2018-0794-5994 Attachment A) looked at four real-world ESP rebuild projects and the costs of three out of the four projects exceed the high end of the EPA's range, with two at almost twice that amount (*i.e.,* about $200/kW). Based on the four real-world ESP rebuilds, the mean cost is $133/kW. The commenters said that the cost effectiveness ratio, based on the EPA's unrealistically low "baseline fPM rates" but adjusting for a minimum compliance margin of 20% and a mean cost for ESP rebuilds of $133/kW, would increase from a maximum of $14,700,000 estimated by the EPA to about $22,000,000 per ton of total non-Hg metal HAP removed.

Response 2: The Agency responds to the comment on costs of ESP rebuilds in section IV.C of the preamble.

We recognize that the rule's changes may impact requirements from other permitting actions or consent decrees; to the extent that EGU owners or operators wish to merge and/or revise those other actions or decrees with the rule's requirements, they should contact and work with the respective regulatory authorities.

Comment 3: Commenters stated that the EPA must take the unique attributes of small entities into account when setting the time frames required for installation of fPM upgrades or new controls. The commenters said that cooperatives have specific parameters unlike most investor-owned utilities. Revenue availability impacts the timing of projects. They said in addition to this 2023 Proposal, the EPA's suite of other environmental regulations for GHGs, effluent limitations guidelines, ozone season NOx, and coal ash also require significant expenditures within the same time period (2025-2030).

Commenters stated that the EPA is correct that a standard that would require a capital expenditure of $52 million for a single unit would likely result in the shutdown of the West Virginia EGU. The commenters said that the same is surely also true, however, for all units that would be required to expend close to $40 million and more in capital cost to upgrade control equipment as a result on the Proposed Rule. They asserted that this is especially true given that the EPA also has recently proposed other rules that are likely to result in a large number of coal-fired EGUs electing to shut down by 2032. The commenters said that in the current, uncertain climate regarding the viability of any coal-fired EGU past 2032, the 2023 Proposal is likely to result in substantially more shutdowns that the mere 500 MW the EPA estimated and if the Agency insists on proceeding with the proposed standard, it must realistically assess the viability of these EGUs and account for their shutdown in evaluating the cost effectiveness and impact of the 2023 Proposal on cost as well as the reliability of the electric grid.

Commenters stated that it is hardly necessary to elaborate on this issue with respect to the alternative fPM standard of 0.006 lb/MMBtu. The commenters said that the capital cost of FF construction exceeds that of major ESP upgrades significantly. Given the economic and regulatory climate (including the proposed ELG and CAA section 111(d) proposals), a revised standard that would require the installation of a FF on an EGU that currently has no such controls would surely doom such a unit to shut down. The commenters argued that the premature shutdown of a minimum of 52 EGUs by mid-2027 would increase the cost of this 2023 Proposal substantially and would have a devastating effect on reliability.

Commenters noted the EPA fails to account for the reduction in remaining useful life and utilization that also may result from the EPA's other rulemakings targeting Colstrip, including the Proposed Coal Combustion Residue Rule and the Proposed GHG Rule. They expressed concern that with a limited lifespan and limited generation to recoup the costs, Colstrip is far more likely to suffer a premature retirement with the potential for serious economic disruption and impacts on grid reliability and transmission.

The commenters said that in its evaluation of the impact of the proposed standard, the EPA claims this rule would result in only about 500 MW of shutdowns. The commenters said that those shutdowns, it turns out, correspond to a single unit at a West Virginia power plant, which, at $100/kW, would require an ESP upgrade with a capital cost of about $52 million.

Response 3: The Agency thanks the commenters for these comments. The Agency has discretion under CAA section 112(i)(3)(A) to establish compliance dates "as expeditiously as possible, but in no event later than 3 years after the effective date of such standard." The Administrator, as described in CAA section 112(i)(3)(B), may also "issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards." The EPA has finalized the 3 years compliance date for the fPM standard as discussed in section III.C of the preamble.

Regarding comments that the rule is likely to result in substantially more shutdowns than the EPA projected, we direct these responses to Chapter 8 of this document.

As the Agency is not finalizing a more stringent emission limit of 0.006 lb/MMBtu, these comments do not require a response. The rationale for the final standards is discussed in section IV.D of the preamble.

2.6.2 Cost-Effectiveness Comparisons

Comment 1: Commenters stated that cost effectiveness is an important consideration in technology review under CAA section 112(d)(6) and indeed, the EPA undertook cost effectiveness analyses for three possible fPM standards: 0.015, 0.010, and 0.006 lb/MMBtu. They said that largely based on these analyses, the EPA is proposing a revised standard of 0.010

lb/MMBtu; and it rejected the lower, 0.006 lb/MMBtu standard because it is not cost-effective, although it also is soliciting comments on this more stringent standard. Commenters also expressed concern that the EPA's rationale is not only arbitrary on its face, but it is also arbitrary because it reverses, without explanation, the EPA's prior acknowledgements that cost effectiveness should account for the cost effectiveness of imposing controls at each affected facility, and not simply on an aggregate nationwide basis. They stated at the very least, these costs should factor strongly into the EPA's assessment of what is "necessary" pursuant to the provisions of CAA section 112(d)(6) and CAA section 112(f)(2).

Commenters referenced the NRECA technical evaluation for this 2023 Proposal entitled "Technical Comments on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology" (Technical Report). The commenters stated that the NRECA Technical Report finds meaningful errors in the EPA's cost analysis that must be corrected. They said the errors lead to sizeable cost per ton underestimates that erode the EPA's overall assumption that the proposal is cost-effective.

Response 1: The EPA thanks commenters for these comments. The rationale for the final emission standards is discussed in section IV.D of the preamble.

Comment 2: Commenters stated that for the proposed 0.010 lb/MMBtu standard, the Agency estimates that the revised standard would only impact 20 affected EGUs and bear an annual cost between $77.3 million and $93.3 million for a total fPM reduction benefit of 2,074 tpy and total non-Hg metal HAP reduction of 6.34 tpy. A reduction of 6.34 tpy is equivalent to a 2.57% reduction of total non-Hg metal HAP emissions reported for this sector compared to 2020 emission rates. The commenters said that across all emission sectors the proposed reduction represents a 0.30% reduction of fPM emissions compared to 2020 emission rates.

Commenters believed that the proposed 0.010 lb/MMBtu standard is not cost-effective. The commenters said that these are small reductions, at high cost and based on the costs and emission reductions, the EPA calculated a cost effectiveness ratio (*i.e.,* the estimated cost to reduce one ton of total non-Hg metal HAP) of $12,200,000 to $14,700,000. Commenters stated that even assuming that the EPA's unrealistically low fPM baseline cost effectiveness ratio is correct, the EPA's proposal to revise the fPM standard to 0.010 lb/MMBtu based on cost effectiveness of up to $14.7 million per ton of total non-Hg metal HAP removed (equivalent to $44,900 per ton of fPM removed) is inconsistent with the EPA's prior actions. The cost effectiveness ratio that the EPA says in this proposal is acceptable is substantially higher than the cost effectiveness ratio the Agency has previously found to be decidedly not cost-effective. They further said that the Agency uses the cost effectiveness ratio as a tool to compare against cost effectiveness values from other proposed regulations in determining reasonableness and in the past, the EPA has decided against revising fPM (which is typically used as a surrogate for non-Hg metal HAP) standards based on cost effectiveness ratios substantially lower than the cost effectiveness here. They said that the EPA should follow these precedents and acknowledge that the proposed $12.2 to $14.7 million per ton of non-Hg metal HAP reduced is not cost-effective. They argued that the Agency should not finalize the proposed standard of 0.010 lb/MMBtu for that reason. By the same token, the alternative, more stringent standard of 0.006 lb/MMBtu is even more grossly not cost-effective. The commenters said that at a cost effectiveness of $25.6 million per ton of non-Hg metal HAP reduced, the alternative standard of 0.006 lb/MMBtu should not even be considered.

Commenters provided the following examples of previous rulemakings found not cost-effective:

- In the EPA's technology review for the Petroleum Refinery Sector, the Agency considered a lower fPM emission standard for existing fluid catalytic cracking units. They said that the EPA found that lowering the standard would cost more than $10 million per ton of total non-Hg metal HAP reduced (in that case, equivalent to $23,000 per ton of fPM reduced) and argued that the Agency decided against revising the standard because it was not cost-effective.
- In the Iron Ore Processing technology review, the EPA considered revising the non-Hg metal HAP standard but found that implementing wet scrubbers incurred a cost effectiveness of $16 million per ton of non-Hg metal HAP and that the Agency decided against revising the standard because it was not cost-effective.
- In the Integrated Iron and Steel Manufacturing Facilities technology review, the EPA contemplated a standard that would require upgrading all fume/flame suppressants at blast furnaces to baghouses to control non-Hg metal HAP emissions. They said the Agency found a proposed standard would cost $7 million per ton of non-Hg metal HAP reduced and concluded that the controls were not cost-effective, and made a similar finding for a proposed standard that would have cost $14,000 per ton of volatile HAP reduced.
- In considering beyond-the-floor MACT for Portland Cement Manufacturing, an evaluation that also considers cost effectiveness, the EPA decided against imposing a more stringent non-Hg metal HAP standard because it resulted in "significantly higher cost-effectiveness for PM than EPA has accepted in other NESHAP." They said the EPA noted in that rulemaking that it had previously "reject[ed] $48,501 per ton of PM as not cost-effective for PM," and noted prior EPA statements in a subsequent rulemaking providing that $268,000 per ton of HAP removed was a higher cost-effectiveness value for PM than the EPA had accepted in other NESHAP standards.

Commenters stated that considering the "cost-effectiveness" of the 0.010 lb/MMBtu limit, the upper limit of the projected annual costs per ton of fPM are substantially lower than the per ton costs that the EPA has considered to be cost-effective in other technology reviews; thus, the EPA should strengthen the standard to at least 0.010 lb/MMBtu.

Response 2: The Agency thanks commenters for providing these comments. The rationale for the final emission standards is discussed in section IV.D of the preamble.

Comment 3: Commenters agreed with the EPA that lowering the standard to 0.006 lb/MMBtu at $25.6 million per ton of total non-Hg metal HAP reduced is not cost-effective.

Commenters stated that EPA concludes that units without baghouse technology, such as ESP-only units, would need to install a baghouse (FF technology) to achieve a limit of 0.006

lb/MMBtu. The commenters said that cost implications are particularly significant for electric cooperatives. Baghouse technology is estimated to cost $282,715 per fPM ton. They argued that the cost of that retrofit project would force unit retirements in an already burdened sector.

These commenters stated there is no doubt that meeting that lower emissions rate is technologically feasible using currently available controls and they urge the EPA to adopt the 0.006 lb/MMBtu limit. The commenters said Andover Technology Partners found that the cost to comply with an emission standard of 0.006 lb/MMBtu, (the more stringent alternative considered by the EPA in the 2023 Proposal), on a fleetwide basis is significantly less than the cost estimated by the EPA. Andover Technology Partners attributes this difference "to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu." *Id*. Commenters stated that though cost effectiveness on a dollar-per-ton basis is less relevant in the CAA section 112 context than with other CAA provisions, the $103,000 per ton of fPM and $209,000 per ton of filterable $PM_{2.5}$ estimates that the EPA calculated for the 0.006 lb/MMBtu standard are reasonable and comparable to past practice regarding technology reviews under CAA section 112(d)(6). They stated that the EPA has previously found a control measure that resulted in an inflation-adjusted cost of $185,000 per ton of $PM_{2.5}$ to be feasible and cost effective for the ferroalloys production source category and proposed a technology review for secondary lead smelting sources costing an inflation-adjusted $114,000 per ton of fPM. Using the ATP cost estimate, the 0.006 lb/MMBtu standard has even better cost effectiveness at about $72,000 per ton of fPM and $146,000 per ton of filterable $PM_{2.5}$. The commenters further said that the EPA also calculated the cost effectiveness based on unit-specific heat input and allowable emissions at $1,610,000 per ton, showing that a standard of 0.006 lb/MMBtu allows far less pollution at low cost to the power sector. They concluded that all of these metrics and approaches to considering costs show that an fPM standard of 0.006 lb/MMBtu would require cost-effective reductions and can be achieved at a reasonable cost that would not jeopardize the power sector's function.

Commenters stated that while there are better and more appropriate cost metrics and considerations in the context of CAA section 112, it is also worth noting that the benefits of an fPM standard of 0.006 lb/MMBtu far outweigh the costs. They said that the EPA projects annual net benefits of this standard to be $1.1 billion in the RIA. Due in part to the challenge of monetizing the benefits of HAP reductions these benefits are primarily co-benefits, but the combination of quantified and unquantified benefits clearly justifies the modest cost, and the fact that the EPA likely underestimates the benefits and overestimates the costs of this standard in the RIA suggests the net benefits may be even higher than projected. The commenters said but even based on the EPA's projections, the environmental and public health benefits of setting the fPM standard at 0.006 lb/MMBtu clearly far outweigh the costs, further indicating that the costs of this standard are reasonable.

Response 3: The Agency appreciates commenters for raising these comments. The rationale for the final emission standards is discussed in section IV.D of the preamble.

Comment 4: Commenters stated that the cost effectiveness estimates for actual or allowable emissions are exorbitant and would easily serve as a basis to take no action at all, especially given the acceptable level of risks identified in the risk review.

Commenters noted that the EPA also includes in the record cost effectiveness values "based on allowable" emissions that are, of course, lower than the relevant, actual cost effectiveness values discussed above. The EPA says it included these values for the following reason:

> "Because this cost-effectiveness evaluation [commenters added: *i.e., that based on actual emission performance and expected reductions and cost*] only considers improved fPM control needed at a few units and not the entire fleet, we also evaluated an alternative cost-effectiveness approach that considers allowable emissions, assuming emission reductions achieved if all evaluated EGUs emit the maximum allowable amount of fPM (*i.e.*, at the current standard of 3.0E–02 lb/MMBtu), and the associated costs for EGUs to comply with the three potential fPM standards." (88 FR 24870)

Commenters stated that this stated reason is a non sequitur, all the more so, given that here the EPA candidly concedes: "This cost-effectiveness approach using allowable emissions is not comparable to the standard methodology used in CAA section 112 rulemakings, [but does consider if the fleet were operating at levels allowed by the 2012 MACT rule.]" (2023 Technology Review Memo pg. 12, EPA-HQ-OAR-2018-0794-5789). The commenters argued that these cost effectiveness numbers – based on what they described as counter-factual imaginary reductions in fPM/non-Hg metal HAP from an imaginary situation in which every EGU in the EPA's database is operating at the current 0.030 lb/MMBtu fPM limit and thus their reductions at zero cost are nonetheless attributable to the proposed revised standard – are not otherwise used or discussed in the rulemaking and for good reason, as they are irrelevant and by the Agency's own admission, "not comparable" (*Id.*) to the standard methodology used in all previous RTR as well as beyond-the-MACT-floor rulemakings. The commenters said that what they seem to be, however, is a tacit, further concession by the EPA that the actual cost effectiveness values for this Proposed Rule, which are comparable to the methodology used in CAA section 112 rulemakings, are so much higher than values the EPA has previously found to be not cost-effective, that the Agency found it useful to float irrelevant, but lower cost effectiveness values based on "allowable" emissions. The commenters concluded that any reliance by the EPA on the latter cost effectiveness values, contrary to the standard methodology heretofore used in CAA section 112 rulemakings, would be arbitrary and capricious.

Response 4: The Agency disagrees with commenters that the allowable cost effectiveness values presented in the proposal are exorbitant and irrelevant. The Agency presented this alternative cost effectiveness ratio to demonstrate that a lower fPM standard may be cost-effective if EGUs were performing at the 0.030 lb/MMBtu emission limit. This approach has not been used for other rulemakings as overcompliance with a numerical emission limit is rare. The rationale for the final emission standards is discussed in section IV.D of the preamble.

2.6.3 Compliance Margin

Comment 1: Commenters conveyed that most EGUs typically operate well below the limit to allow for a compliance margin in the event of an equipment malfunction or failure because sources need to operate below current limits established in the 2012 MATS Final Rule at all times, which they encouraged the EPA to consider when setting new limits. Commenters claimed with the proposed fPM limit of 0.010 lb/MMBtu, an appropriate design margin of 20% necessitates that control technologies must be able to achieve a limit of at least 0.008 lb/MMBtu or lower. They expressed concern that EPA fails to take design margin into consideration in the cost analysis. They stated that by ignoring the need for a design and operating margin cited in at least two of the Agency's publications (Hutson, 2012 and Parker, 2023), the EPA underpredicts the number of units that would require retrofits.

Commenters stated that the EPA must add a compliance margin in its achievability assumptions. They argued that the EPA misjudges the number of EGUs that must undertake retrofits by failing to factor in a compliance cushion. The commenters said that the EPA has long recognized that a design/compliance margin is needed due to operational variability and recognized this concept in the context of the original MATS technology analyses. They said a margin of at least 20% is industry-standard and identified in the 2012 Control Needs Memo.

Commenters stated that in the cost analysis, the EPA did not assign a design/compliance margin and by making this choice, the EPA underestimates the number of units that require retrofits. They said the Technical Analysis (EPA-HQ-OAR-2018-0794-5956 Attachment 1) revises the cost analysis to adjust the number of units requiring upgrades to total 26 ESPs to meet 0.010 lb/MMBtu and projects a much higher project cost based on actual project build cases. The commenters said that to achieve 0.006 lb/MMBtu, 52 ESP-equipped units would need to retrofit to a baghouse, and 23 units with baghouses would need to adopt an enhanced operation and maintenance protocol, increasing the EPA's estimate (65 versus 87). The commenters said that the cost per ton value is considerably higher with the additional retrofits and higher project costs and they included a table showing that this results in a very significant cost difference: with the EPA's average cost/ton being $37,300-$44,900 for 0.010 lb/MMBtu proposed rate compared to the Technical Analysis cost/ton being $67,262 and the EPA's average cost/ton $103,000 for 0.006 lb/MMBtu proposed rate compared to the Technical Analysis cost/ton being $282,715.

Commenters requested that the EPA revise its cost analysis, apply appropriate cost values based on representative projects, and then apply at least a minimum of 20% compliance margin in the cost analysis to adequately reflect the number of units that would need to undertake fPM control upgrades.

The combination of a very low fPM standard and having to account for measurement uncertainty and correlation methodology for PM CEMS would likely necessitate an "operational target limit" of 50% of the applicable limit – *i.e.,* a compliance margin of 50%, as the EPA seems to recognize in the docket. The commenters said that even using the EPA's unrealistic "baseline fPM rates" and the lowest possible compliance margin of 20%, the NRECA technical evaluation estimates that 37 units – almost twice as many as the EPA's estimate – would be required to take substantial action to comply with the proposed standard.

Response 1: The Agency has responded to this comment in section IV.C of the preamble.

2.7 Alternatives to Proposed 0.010 lb/MMBtu Limit

Comment 1: Commenters reiterated that the 2012 MATS Final Rule (77 FR 9304) established a limit on fPM as a surrogate for non-Hg metal HAP based on the primary technologies for controlling fPM being an ESP and/or FF and the EPA's 2023 Technology Review memo shows that across the country, all but two existing coal- and oil-fired power plant units, Colstrip Units 3 and 4, now operate one or both of these technologies and have achieved fPM emissions rates lower than the current standard of 0.030 lb/MMBtu. A few commenters advocated that the EPA adjust the standard for non-Hg metal HAP emissions to 0.020 lb/MMBtu or 0.024 lb/MMBtu or greater rather than the proposed limit of 0.010 lb/MMBtu, which reflects the average performance of the top 50% of the best performing units evaluated by the EPA for the 2023 Proposal. Commenters recognized that a fPM standard of 0.024 lb/MMBtu would not compromise the ability of the power sector to provide affordable and reliable electricity that can be achieved at a reasonable cost, particularly when considering coal unit retirements that are likely to occur due to the current policy environment and other regulations. Commenters suggested that a limit of 0.024 lb/MMBtu should be achievable by Colstrip Units 3 and 4. Certain commenters felt a limit of 0.025 lb/MMBtu fPM may be more achievable, especially as compared to the 0.010 lb/MMBtu fPM limit, as it would at least provide Colstrip an opportunity to try to meet the limit without new control technology given its unique circumstances.

Commenters suggested that relevant to Colstrip, the EPA should lower the standard for non-Hg metal HAP emissions to no higher than 0.024 lb/MMBtu, rather than the proposed limits of 0.010 lb/MMBtu or 0.006 lb/MMBtu. Commenters noted that Colstrip has typically been able to remain just below the current limit of 0.030 lb/MMBtu; however, due to occasional variability in fuel and operating conditions, Colstrip has, since 2018, hired consultants and engineers to explore ways to further enhance the efficiencies of the venturi wet scrubbers. They stated this work has made the venturi wet scrubber emissions more stable, yet the work demonstrated that 0.015 lb/MMBtu fPM is not achievable with upgrades to the existing wet scrubbers and further that the efforts to reduce fPM emissions with the existing control technology has reached its limits. Commenters expressed concern that these comprehensive efforts reflect all known upgrades available to be implemented to the Colstrip scrubber/combustion process to reduce fPM, which enables Colstrip to achieve compliance with the current 0.030 lb/MMBtu fPM limit with an adequate compliance margin, while the majority of stack testing has shown emission rates between 0.020 lb/MMBtu and 0.025 lb/MMBtu fPM with several instances where stack tests were above 0.025 lb/MMBtu fPM.

Commenters further stated the EPA should not finalize the 0.010 lb/MMBtu fPM limit, but should the EPA do so, the Agency should establish subcategories so that it accounts for Colstrip's unique design and circumstances and establish a subcategory for coal-fired units that use wet scrubbers to address both SO_2 and PM, and that do not have ESPs or FFs, where the fPM limit for those units is no lower than 0.025 lb/MMBtu pursuant to its authority under 42 U.S.C. § 7412(c)(5).

Commenters stated that Colstrip is in full compliance with the current MATS standards, which the EPA does not dispute meet the statutory objectives of the CAA. They said, however, as the EPA also acknowledges and Talen explains in detail, Colstrip cannot come into compliance with either of the candidate standards set forth the 2023 Proposal without extensive supplementation of existing pollution controls – the venturi wet scrubbers currently in use cannot meet the proposed standards. The commenters stated that as detailed by Talen, upgrading Colstrip to comply with the 2023 Proposal is cost-prohibitive, resulting in at least $350,000,000 in capital costs, plus an additional $15 million annual operating costs. They said Colstrip is the only facility identified by the EPA as facing this predicament. The commenters also noted that the 2023 Proposal, in combination with the other proposed rules, disincentivizes superior performance. The commenters stated that as detailed by Talen, the venturi scrubbers control both SO_2 and fPM and Colstrip has been a high performer in SO_2 emission reduction for years because of that system, but under the 2023 Proposal Colstrip would be punished for having "wrong" system to control fPM, in comparison to other facilities. The commenters argued that that no other utility bears anywhere close to the burden that they would bear under the 2023 Proposal.

Commenters stated that in addition, if Colstrip is closed in the near term, adequate and reliable electrical service will not be able to be provided to Montana customers without new replacement baseload capacity. The commenters stated that Colstrip currently plays an essential role in baseload capacity for NorthWestern, and there are no near-term feasible means to replace Colstrip's capacity with other existing NorthWestern capacity or market purchases from in-state or out-of-state sources. The commenters stated that imported power is further constrained by significant transmission limitations.

Commenters have modeled and evaluated scenarios for closure of Colstrip in 2025, 2030, and 2035, and 2042 in its May 2023 Integrated Resource Plan. The 2025 and 2030 closure scenarios expose NorthWestern to extreme degrees of market risk, resulting high probabilities of ruinous market electricity purchases and grid instability.

Commenters stated that if they participate in upgrades to Colstrip, they will either need to materially increase electricity rates for Montana customers, or redirect funding previously earmarked for other projects - projects that may be abandoned to fund Colstrip upgrades include transmission improvements, planned upgrades to facilities that are in excess of maintenance requirements, or other non-required beneficial capital projects. The commenters stated that the vast majority of these have direct environmental benefits, deferral of which would undermine or even fully negate the environmental benefits of the 2023 Proposal. The commenters stated that alternatively, the only baseload capacity that can conceivably be constructed within the statutory compliance deadlines is new natural gas generation capacity. The commenters stated that carbon-free baseload alternatives are either unproven or require significantly longer development times. They said that the net result would be a substantial investment in a new, large, long-lived fossil fuel based generation assets and this outcome would clearly contradict the objectives of Executive Order 13990. Commenters also stated that the adverse net environmental consequences of capital reallocations from the subjects identified above would be reduced utilization of renewables, slowing progress toward the commenters' Net Zero 2050 objectives. The commenters stated that perversely, a very plausible scenario under the 2023 Proposal, if implemented in its current form, would be to extend the life of Colstrip, and result in the heavier utilization of Colstrip than in the absence of the 2023 Proposal. Commenters said they have not had the opportunity to fully calculate the emissions consequences, but there is a significant likelihood that, as applied to Colstrip, the 2023 Proposal would have the effect of increasing net carbon and HAP emissions over Colstrip's remaining life than if Colstrip is exempted from the 2023 Proposal. The commenters stated that such a result would certainly be contrary to the objectives of Executive Order 13990.

Commenters stated that they have been substantially and uniquely prejudiced by the EPA's course of action. The stated that the 2020 Final Action confirmed that Colstrip's pollution controls satisfy the requirements of the CAA, and there have been no significant technological or implementation advancements since the 2020 RTR that would change that conclusion. The commenters stated that had commenters known that the EPA would undertake a complete reversal of the conclusions of the 2020 RTR just three years later, they could have factored compliance costs earlier and more robustly into their Integrated Resource Planning process.

Commenters stated that their source portfolio generally generates enough energy to serve average load, but is significantly short on both peaking and flexible capacity. They said that a key reason that they did not plan for new baseload capacity was that they had made substantial investments in Colstrip to comply with the 2012 MATS Final Rule and regional haze requirements. Commenters said they knew that Colstrip would be able to achieve CAA statutory and health-based standards over the medium-to-long term. Commenters said they had contemporaneous public assurances from the EPA to that effect. Commenters said they knew that there were no significant pollution control technology advancements in the offing that would change control performance and consequently, the 2019 ERPP and 2020 Supplement focused investment on the identified peaking and flexible capacity needs, as well as improving transmission capabilities.

Commenters stated that they currently plan to invest over $2.4 billion in capital outlays over the next five years. The commenters stated that many of these investments are required by law and others are intended to improve system reliability, better utilization of renewables, or other projects (*e.g.,* wildfire mitigation) with demonstrable and significant environmental benefits.

Commenters stated that 2023 Proposal costs would constitute significant increase in capital commitments, weighted toward the earlier part of the five years and could imperil the ability to make those critical investments.

Commenters stated that any rate increases to cover 2023 Proposal Costs would be on top of other recent rate increases funding the existing capital and operational budgets. The commenters stated that presently pending before the MPSC is a 28% residential electricity rate settlement, driven in material part by investments in carbon free and reduced-emissions projects. They asserted that the 2023 Proposal Costs did not factor into the settlement. Commenters were uncertain that the MPSC would approve cost recovery for such a large new increase on top of other recent increases and may not approve any portion of it. The commenters stated that as a result, the most likely outcome of the 2023 Proposal Costs would be to force commenters to evaluate postponing or abandoning previously approved capital projects.

The commenters said they support the EPA's efforts to establish appropriate limits on Colstrip's emissions of HAP. They said the EPA explains, exposure to these pollutants harms human health, including "potential neurodevelopmental impairment, increased cancer risks, and contribution to chronic and acute health disorders, as well as adverse impacts on the environment." (Final Rule, Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding, 88 FR13956, 13968 (Mar. 6, 2023)). They said because of the proximity of the Northern Cheyenne tribal members to the Colstrip plant-living both on the Reservation and in the nearby community of Colstrip, where many tribal members are employed-they are disproportionately impacted by exposure to HAP.

The commenters stated that although cost-effective pollution controls are available to reduce toxic air emissions from Colstrip Units 3 and 4, namely baghouses and ESPs, Colstrip's owners have refused to install them and as a result, Colstrip has the highest rate of fPM emissions (a surrogate for non-Hg HAP) in the country and is the only plant still operating without industry-standard PM controls. They asserted that Colstrip has a history of exceeding even the current standard for non-Hg HAP.

The commenters stated that two of Colstrip's owners-NorthWestern Energy and Talen Montana-and Rosebud mine owner Westmoreland oppose the EPA's proposal to strengthen the MATS rule to align with CAA requirements. They said that according to the companies, compliance with lower limits for non-Hg HAP would be too costly. The commenters said that such arguments irresponsibly ignore the acute health effects-including premature deaths that Colstrip's toxic emissions have on Northern Cheyenne tribal members and the many others who live in close proximity to the plant.

The commenters urged the EPA to finalize MATS and said that under the new standards, Colstrip Units 3 and 4 should be required to install the same controls that other plants around the country have already installed and to operate those controls to achieve maximum emission reductions, as the CAA requires per 42 U.S.C. § 7412(d)(2), (f).

Response 1: The EPA thanks commenters for providing additional information and fPM compliance data for the Colstrip facility, which has been considered when establishing the final emission standard. Setting an alternative emission limit of 0.025 lb/MMBtu through subcategorization requires distinction among class, type, and size of sources. Given the similar characteristics of this facility, which is not unique in its design and circumstances compared to the rest of the fleet, the EPA disagrees with the notion that a lower standard for a subset of coal-fired EGUs is warranted. In fact, the only difference in circumstances that the EPA is aware of is the use of less-effective PM controls at Colstrip. Specifically, Colstrip is the only facility that the EPA is aware of using a venturi wet scrubber as the only means for fPM controls. The venturi wet scrubber has not been effective maintaining fPM rates below the current standard of 0.030 lb/MMBtu, as other commenters have pointed out previous fPM rate exceedances. As described in the 2024 Technical Memo, Colstrip is the only facility the EPA estimates need an FF install to comply with a 0.010 lb/MMBtu standard. Further rationale for the final emission standards is discussed in section IV.D of the preamble.

Regarding comments about the impact of closing Colstrip on reliable electrical service, facilities may request an additional time extension through the Department of Energy under the Federal Power Act section 202(c), which are made on a case-by-case basis based on a substantial need for grid reliability. In addition, as other commenters have noted, NorthWestern Energy has recently joined the Western Resource Adequacy Program ("WRAP"), a regional reliability planning and compliance program in the West.

Comments supporting a lower fPM rate for the Colstrip facility are supportive of the Agency's position and do not require a response.

Comment 2: Commenters suggested further strengthening of the limit is essential because EGUs have seen significant improvements in fPM emissions rates since 2011 due to wider deployment of fPM control technologies on units projected by the EPA to be operating in 2028 which present a variety of approaches to lower fPM emission limits with implications for upgrades and actions required to meet a revised standard for fPM. Commenters felt an even stronger level could yield more health benefits and prevent hospital and emergency department admissions for cardiovascular and respiratory illnesses. Commenters in support of a lower more stringent limit stated that a fPM standard of 0.0024 lb/MMBtu would encourage many coal-fired EGUs to choose better-performing controls to achieve greater emission reductions using available control technologies in various configurations. Commenters suggested that the finding and fact that emissions performance still varies significantly not only supports revising the standards, but also provides support for a standard significantly below the proposed level of 0.010 lb/MMBtu. Commenters conveyed that the lagging performers in the coal fleet in particular are not even close to achieving the maximum degree of reduction in HAP emissions that can be achieved with proven controls and should be required to reduce their emissions further.

Response 2: We agree with commenters that further strengthening the fPM limit is essential. The rationale for the final emission standards is discussed in section IV.D of the preamble.

Comment 3: As an additional alternative, the EPA should establish a subcategory with units making an enforceable commitment to retire, where the fPM limit remains at 0.030 lb/MMBtu through retirement. Commenters expressed that the EPA's proposal to make the fPM limit more stringent, as well as require CEMS to demonstrate compliance with that limit, has far-reaching ramifications for EGUs, particularly given Colstrip's unique design and circumstances.

Response 3: The EPA's response about establishing a subcategory for EGUs making retirement commitments is provided in Chapter 2.5.2 of this document.

CHAPTER 3

3. PM Emission Monitoring

Comment 1: Commenters said that PM CEMS could be used to demonstrate compliance with the emission limits of 0.010 lb/MMBtu and 0.006 lb/MMBtu, based on compliance reports showing even lower levels at units with PM CEMS and technical information about the capability of PM CEMS. They said that the fact that PM CEMS have been used to demonstrate compliance in a majority of units in the eight best performing deciles provides strong evidence that PM CEMS can be used effectively to measure low levels of PM emissions, down to a revised standard of 0.0024 lb/MMBtu. The commenters said that the 2023 ATP Assessment notes that PM CEMS are capable of demonstrating PM levels down to 0.0015 lb/MMBtu or less, and that the main concern is calibration. They stated that the EPA's memorandum on PM CEMS Random Error Contribution by Emissions Limit (PM CEMS Memo) suggests that by increasing the sampling time to 8 hours for a standard of 0.003 lb/MMBtu an average random error contribution of less than 41% can be achieved. The commenters argued that while the cost of the PM CEMS may increase as a result, it is still reasonable, and PM CEMS can and should be required for compliance with a standard of 0.0024 lb/MMBtu.

Commenters stated the EPA must require the use of PM CEMS to monitor their emissions of non-Hg metal HAP. PM CEMS are now more widely deployed than when MATS was first promulgated, and experience with PM CEMS has enabled operators to more promptly detect and correct problems with pollution controls as compared to other monitoring and testing options allowed under MATS (*i.e.,* periodic stack testing and parametric monitoring for PM), thereby lowering HAP emissions. Commenters stated employing PM CEMS as the only monitoring option for non- Hg metal HAP—and complying with the revised emissions standards reflecting these improvements in monitoring—is "achievable." In addition, they said the use of PM CEMS is also cost-reasonable for compliance demonstration. As the EPA notes, the EUAC for PM CEMS is also "less expensive than quarterly [stack testing]." The commenters said that given the cost estimates in the Proposal and the estimate by Andover Technology Partners, total costs of installing PM CEMS for the set of plants that do not currently have PM CEMS would be clearly reasonable, especially since PM CEMS is both more effective and less costly than periodic stack testing.

Commenters stated their FWE200DH PM CEMS is able to detect PM at the levels proposed in the rule. Their unit uses light scattering technology that can detect as low as 0.1 mg/m3.

Response 1: The Agency agrees that the collected data demonstrate that a filterable PM limit of 0.010 lb/MMBtu is achievable now for PM CEMS. While PM CEMS are able to produce values at lower levels provided correlations are developed appropriately, the Agency selected this limit in consideration of factors such as run times necessary to develop correlations, potential random error effects, and costs. The Agency agrees use of CEMS in general and PM CEMS in particular enable owners or operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. As described in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs*, available in the docket, the EPA calculated average costs for PM CEMS and quarterly testing from values submitted by commenters in response to the proposal's solicitation; these values are discussed in section IV.D of the preamble. While the average EUAC for PM CEMS exceeds the average estimated annual cost of quarterly Method 5I emission testing, the benefits associated with PM CEMS, such as providing continuous emissions data to EGU owners or operators, regulators, or nearby community members, are not included with commenters' estimated values. As a reminder, the EPA is not obligated to choose the most cost-efficient manner for compliance demonstrations, even though cost can be an important consideration. Consistent with the discussion contained in 88 FR 24872, the Agency finds the transparency and ability to detect and correct potential control or operational problems quickly, makes PM CEMS the best choice for this rule's compliance monitoring. Finally, the Agency appreciates the PM CEMS manufacturer providing laboratory detection levels for one of its instruments; the value provided is about two orders of magnitude below the selected limit, suggesting that the limit can be measured appropriately by this instrument.

Comment 2: Commenters stated the EPA must require units that use HCl as a surrogate for acid gas HAP to monitor HCl using CEMS as part of its CAA section 112(d)(6) review as this will reduce emissions. They said currently, facilities may use quarterly stack testing for compliance that shows regulators and the public little about emissions in the many days and hours between stack tests when emissions could be much higher than during a planned test. HCl CEMS are now more widely deployed in many industries such as municipal waste combustors, cement plants, and biomass and other power generating units than when MATS was first promulgated, and experience with HCl CEMS has enabled operators to more promptly detect and correct problems with pollution controls as compared to other monitoring and testing options allowed under MATS (*i.e.,* periodic stack testing). The commenters said that for units that demonstrate compliance using the HCl limit, employing HCl CEMS as the only monitoring option for HCl would be both achievable and cost-reasonable and that HCl CEMS analyzers cost approximately $80,000 to $250,000, not including the costs of commissioning and startup testing, which may be in similar amounts, which is reasonable.

Commenters stated that several provisions of the CAA give the EPA authority to mandate the use of HCl CEMS for compliance demonstration for acid gas HAP. CAA section 112(b)(5) provides: "The Administrator may establish, by rule, test measures and other analytic procedures for monitoring and measuring emissions, ambient concentrations, deposition, and bioaccumulation of hazardous air pollutants." Separately, CAA section 114(a)(1)(C) authorizes the Administrator to require operators "on a…continuous basis…to…install, use, and maintain such monitoring equipment, and use such audit procedures, or methods…as the Administrator may reasonably require." And CAA section 114(a)(3) provides: "The Administrator shall in the case of any…owner or operator of a major stationary source…require enhanced monitoring…." The commenters said that the EPA's conclusions as to HCl CEMS in the original MATS rulemaking does not pose any obstacle to adopting such requirements now. They said the 2011 MATS rule presents lower initial costs and annual costs for HCl CEMS than for PM CEMS. In that rulemaking, the agency found that the operation and maintenance issues for the CEMS mentioned are no different than for other CEMS now in wide use and acceptance by the industry. The commenters said that in light of the EPA's conclusion in the 2011 proposal that HCl CEMS is a reasonable monitoring option, it would be more than "reasonabl[e]" within the meaning of

CAA section 114(a)(1)(C) for EPA to require this monitoring technique as part of a strengthened rule.

Response 2: The Agency disagrees with the commenters' suggestions that HCl CEMS must be required for MATS. The rule's HCl limits were not considered for revision primarily because no new control technologies or improvements have been introduced for HCl emission reductions. Moreover, most EGUs rely on sulfur dioxide emissions as a surrogate for HCl emissions, enabling use of existing SO_2 CEMS as a continuous check on HCl emissions. As mentioned in the original MATS rule preamble, this is logical because acid gas controls remove HCl prior to sulfur dioxide. For these reasons, no changes were made to HCl monitoring.

Comment 3: Commenters stated the EPA should retain all current options for demonstrating compliance with non-Hg metal HAP standards, including quarterly PM and metals testing, LEE, and PM CPMS. They said removing these options goes beyond the scope of the RTR and does not address why the reasons these options were originally included in MATS are no longer valid. Commenters said they have previously raised concerns about PM CEMS that the EPA has avoided by stating that CEMS are not the only compliance method for PM. They stated that previously, the EPA has determined these compliance methods were both adequate and frequent enough to demonstrate compliance. The commenters said that sources would still be required to comply with the limits at all times including between performance tests and the compliance assurance monitoring that the EGUs must perform under other rules will ensure that the requirement of CAA section 63.10000(b) to operate and maintain the control equipment consistently and will provide credible evidence for the Administrator's determination that the requirement is met.

Commenters stated that the EPA should revise the current PM CPMS provisions to remove the requirement to establish an operating limit equivalent to 75% of the standard, especially if the PM standard is lowered to 0.010 lb/MMBtu or 0.006 lb/MMBtu. The commenters said that setting the operating limit to the equivalent to the standard over a 30-day basis will show that the unit and control devices are operating in a way that would be reasonably expected to demonstrate compliance with the PM limit based on and interpolation of the most recent most recent performance test. They said requiring PM CEMS would not remove the uncertainty in measurement as a PM CEMS is still deemed acceptable if just 75% of the data are within 25% of the correlation during an RCA or just two-thirds of the data are within 25% of the correlation for an RRA.

Commenters argued that the EPA erred in not differentiating between stack test data and CEMS data when determining the revised PM standard. They said because stack tests are a snapshot in time, they do not capture the potential seasonal variability and spikes in emissions during load changes or when additional pieces of equipment (*i.e.,* pulverizes, scrubber chambers) are put into service. The commenters argued the EPA should take this into consideration when selecting what data to use when determining the level and compliance requirements of the standard. They also argued the EPA should not select data from certain quarters to set the standard, but instead use all available PM data.

Commenters stated the EPA used 1-hour stack test data to justify the proposed PM standard of 0.010 lb/MMBtu. They said that since the EPA believes this data is reliable enough to set the standard, 1-hour test runs are congruent with the revised standard and appropriate for compliance demonstration.

Commenters stated there is great difficulty in accurately measuring emissions using CEMS for both low-emission normal operations and potentially high-emission non-normal operations. They said allowing flexibility in using separate methods (and equations) during excess emission events to quantity those emissions would be beneficial.

Commenters stated the EPA should not attempt to justify the requirement for all EGUs to demonstrate compliance via PM CEMS by stating that new units require PM CEMS. They said that there are currently no new EGUs in operation and there likely never will be. The commenters said supporting the proposed use of PM CEMS at low fPM concentrations by stating the requirement is consistent with a theoretical requirement for new EGUs that have not been built and will never be built is no support at all.

Response 3: The Agency disagrees with the commenter who suggests that the rule should retain all previous options for demonstrating compliance with either the individual metals, total metals, or fPM limits. As the rule now contains an fPM limit with compliance demonstrated only using PM CEMS, EGU owners or operators choosing to use the fPM limit for compliance purposes would not need to use multimetals CEMS or non-Hg metals testing. However, as mentioned earlier, to the extent that an EGU owner or operator would want to rely on a non-Hg metals emissions limit and to conduct non-Hg metals monitoring, the EGU owner or operator may use the alternative test method provisions in the NESHAP general provisions to request such a limit. As an aside, the Agency is aware of just one EGU that reports non-Hg metals results from testing (the Agency is unaware of any EGU that uses multimetals CEMS for compliance purposes); however, that EGU relies on fPM for compliance purposes. As PM CEMS is now the required compliance demonstration approach for fPM and eligibility for a fPM LEE program – which was not proposed - would be based on a value lower than the fPM limit (0.010 lb/MMBtu), which is one-third of the current fPM LEE eligibility value, the fPM LEE program has been made moot. The PM CPMS approach was included in the original rule as a means for EGU owners or operators to become familiar with PM CEMS operation. As the PM CEMS data demonstrate, PM CEMS, whose usefulness and durability was doubted by some during the initial rule development, have demonstrated their suitability for the electric utility industry such that PM CPMS as training guides are no longer required. The Agency agrees with the commenter who suggests that EGU owners or operators will continue to manage and adhere to parametric monitoring associated with their fPM control devices; however, with the advent of PM CEMS for compliance purposes, the Agency suggests that EGU owners or operators may find cost savings from using their newly-installed PM CEMS to streamline their compliance assurance monitoring (CAM) and similar applicable requirements in their title V permits. As mentioned earlier, the commenter's suggestion to revise PM CPMS monitoring requirements is moot, since PM CPMS are to be replaced with PM CEMS. The Agency does not understand one commenter's suggestion that the tolerance for PM CEMS does not reduce uncertainty; that suggestion seems to conflate acceptable tolerances with uncertainty. Most, if not all, values contained in Agency rules have tolerances. For this rule, the tolerance will be expanded to help ease the transition into PM CEMS. Over time, as EGU owners and operators become familiar with the instrumentation and its operation, the rule may start reducing this tolerance, as has been done in other rules such as in the acid rain monitoring provisions. On the other hand, every measurement has one or more components of uncertainty, and the Agency strives to reduce such uncertainties and prefers to keep such uncertainties below half the measured value. A correlation established using a minimum amount of collected fPM mass should ensure such uncertainties are minimized.

As mentioned earlier, the Agency disagrees with the commenters who suggest that stack test data and PM CEMS data should have been considered separately. MATS imputes both quarterly emission test average values and PM CEMS average values into 30-boiler operating day rolling averages, those values are to account for normal operation which should and would include periods of load and equipment changes. The Agency also disagrees with the commenters who suggest that distinct periods should not have been used when considering appropriate emission limitations because the Agency wanted to obtain emissions information from those periods where demand was highest; that period is believed to occur over in the third quarter of the year. Other operational periods are not expected to have larger or more continuous loads. The Agency believes the commenter who suggests that the Agency used one hour test results as the basis for the revised emission limit is mistaken; as mentioned earlier, MATS uses the equivalent of the average emissions test value as each hourly value from the 30-boiler operating day rolling average compliance period.

While the Agency agrees that measuring very low and non-normal high fPM emissions can be challenging, as long as the correlation equation is determined appropriately, PM CEMS should be able to provide valid responses. In many cases where non-normal high fPM emissions occur, the Agency expects instrumental problems or out-of-control periods might be the cause; if so, then such data would not be included for compliance purposes. Rather, the occurrence, duration, and steps to correct and prevent recurrence will be reported. In any event, the commenter provided no such alternatives or equations for consideration, so no changes will be made to the rule. The Agency disagrees with one commenter's suggestion that PM CEMS are required because new EGUs are already required to use PM CEMS; restating the existing requirement was not intended to be a justification; rather, it was a reminder of how new EGUs are to comply with the rule. It remains accurate to state that new EGUs are required to use PM CEMS and that this requirement is not new or unknown; it was included in the original rule promulgated over 11 years ago.

Comment 4: Commenters noted the similarity of the Portland Cement MACT (40 CFR part 63, subpart LLL) PM monitoring requirements to the proposed PM CEMS requirements and that the EPA rejected the use of PM CEMS in portland cement plants in favor of PM CPMS. The commenters said that the low limits for PM would require impractical run times to reduce uncertainly of measurements during the correlation process and in that industry, the EPA noted the variance in particulate sizes that caused issues with measurements, but they have not addressed that EGUs can have varying sizes of particulate based on specific operational conditions and control equipment. They said that the uncertainty in the Method 5 measurements create a high degree of failures of PS-11, RCA, and RRA failures with emission limits this low and the use of PM CEMS should not be required.

Response 4: The Agency disagrees with the commenters' suggestions that EGUs have similar characteristics as Portland Cement Plants. This issue has already been discussed and addressed in the proposal preamble at 88 FR 24873,

> "…The conditions experienced by portland cement facilities that required revisions to emission limits and compliance determination method are not similar to those expected to be faced by EGU owners or operators subject to MATS. First, the fuel used by coal-fired EGUs is more uniform and its characteristics are more consistent than those of the fuel and additive mixtures used by portland cement kilns. Such fuel combustion particle consistency allows technologies such as light scattering and scintillation, in addition to beta gauges, to be used by PM CEMS for compliance determination purposes. Moreover, consistent fPM particle characteristics for EGUs provide stable correlations for those EGUs with existing PM CEMS; while the fPM particle characteristics provide correlations that remain within specifications, as evidenced by ongoing relative correlation audits, for some EGUs the existing correlations do not change and can continue to be used now and in the future without having to develop a new correlation. Second, the…MATS emission limit of 1.0E–02 lb/ MMBtu, …coupled with [the rule's shift to a minimum sample catch]…~~from a minimum sampling collection time of 3 hours per run, based on a typical sampling rate of 3⁄4 cubic feet per minute~~, avoids the measurement problems described by the Portland Cement NESHAP by reducing the average inherent measurement uncertainty for half of the proposed emission limit (where the EGU is expected to operate) from more than 50 to 80 percent... As shown, inherent measurement uncertainty does not appear to be problematic for the …emission limit…Third, Performance Specification 11 (PS 11) [and Procedure 1], which provide[~~s~~] procedures and acceptance criteria for validating PM CEMS technologies, already anticipate[~~s~~] and include [an] approach[~~s~~] for developing[multi]-level emission correlations for PM CEMS. Those techniques include varying process operations; varying fPM control device conditions; [and] PM spiking …" [6]

EGUs have consistent fuel characteristics in comparison to Portland cement facilities; EGU fuels are typically contracted to meet a certain range of requirements, and control devices which yield ash with uniform characteristics; in contrast, Portland cement facilities combust many various types of fuels with differing ingredients, typically acquired by seeking out lower cost batches, resulting in clinker developed according to cement specification needs, not to uniform particle size specifications. The Agency believes these differences allow PM CEMS use at EGUs.

As mentioned earlier, the Agency believes adjustments from minimum test run duration to minimum fPM mass collection will reduce overall test campaign durations while reducing measurement uncertainty to acceptable levels. One of the commenters reviewed the results from correlation testing, RCAs, and RRAs from 20 EGUs, adjusting tolerances to determine how the

[6] Strikethrough and text in brackets added by EPA from original proposal for clarification.

existing EGUs would fare using the range of potential limits contained in the proposal. That commenter concluded that it may be difficult for EGU owners or operators to meet the proposed limits, especially the ones below 0.010 lb/MMBtu, without additional work. The Agency also reviewed correlation testing, RCA, and RRAs from 32 EGUs and found similar results as that commenter, analysis provided in docket entitled "Evaluation of PM CEMS QA Criteria at Different Emission Limits." However, when the tolerance adjustments were applied in the analysis, the Agency found little difference between the expected performance at 0.020 lb/MMBtu and at 0.010 lb/MMBtu with a revised tolerance. At least 3 EGUs met all criteria for each of the correlation testing, RCA, and RRA procedures at the rule's new fPM limit, even though the EGUs were not trying to operate at emission levels other than 0.030 lb/MMBtu. Moreover, 13 EGUs met the criteria for each of two procedures (as the RCAs occur every 3 years, many of the reviewed results had not conducted RCAs). The Agency's quick check showing at least 80% of existing results could meet the new limit with the revised tolerances without needing further adjustments or repeat testing demonstrates that PM CEMS are well-positioned to operate well at the rule's limit. Therefore, the rule will maintain use of PM CEMS with the revised tolerances.

Comment 5: Commenters stated that the EPA's cost estimates contradict the Agency's suggestion that the use of PM CEMS is a more cost-effective monitoring approach than quarterly testing, especially for units that qualify as LEE. They said that the EPA used estimates from ICAC or Envea/Altech which do not include numerous costs associated with PM CEMS which make them not cost effective, such as the cost of stack testing associated with the PS-11 correlations, and the ongoing costs of RCAs and RRA, which are a large part of the costs associated with PM CEMS and would rise substantially in conjunction with the proposed new PM limits. The commenters said that the ICAC estimated range of PM CEMS installation costs are particularly understated and outdated and should be ignored by the Agency. The commenters said they are willing to meet with the EPA to discuss and correct these cost estimates. They said that the EPA estimates may also understate PM CEMS cost by assuming the most commonly used light scattering based PM CEMS will be used for all applications. The commenters said that while more expensive, a significant amount of beta gauge PM CEMS are used for MATS compliance, especially where PM spiking is used for PS-11 correlation and RCA testing and that this higher degree of accuracy from beta gauge PM CEMS may be needed for sources without a margin of compliance under the new, more stringent emission limit.

Response 5: The Agency has responded to this comment in section IV.C. of the preamble.

Comment 6: Commenters stated PM CEMS do not directly measure PM in the stack, but instead measure some other characteristic that is then related to PM levels. They state this results in PM CEMS not being technically appropriate for all coal-fired units, especially to operate within the proper QA/QC criteria under Procedure 2 and establishing the correlation curve under PS-11, both of which will be even more difficult under lowered emission standards.

Commenters said that an operator would not know if their CEMS fails a QA/QC criteria in real-time, resulting in many hours of invalid data that are not reflective of poor maintenance or operation but rather the difficulties associated with the quality assurance procedure at such low emission levels.

Commenters said that the EPA should include additional provisions in Appendix C of 40 CFR part 63, subpart UUUUU to mitigate the effects of this downtime, such as provisional data periods following a failed RRA or RCA. Alternatively, they said the EPA could require an RCA only if the RRA is unsuccessful. Increased sample volume does not mitigate these challenges, especially calibrating equipment to measure PM levels against a limit of 0.010 or 0.006 lb/MMBtu. Commenters also proposed the EPA consider the use of "QA operating quarters" and "grace periods" consistent with 40 CFR part 75 in the MATS Appendix C.

Commenters stated that the requirements of PS-11 will become extremely hard to satisfy at the low emission limits proposed. For PS-11, RCA, and RRA, the tolerance interval and confidence interval requirements are expressed in terms of the standard that applies to the source. They said that PS-11 states that the 95th percentile confidence interval half range from the correlation test must be within 10% of the PM limit and that the tolerance interval half range from the correlation test must have a 95% confidence that 75% of all possible values are within 25% of the PM limit. The commenters said that test data from operating units was reviewed by the commenter and found to have significantly higher PS-11 failure (>80%), RCA failure (>80%), and RRA failure (60%) rates at the more stringent proposed emission limits. They stated that the cost, complexity, and failure rate of equipment calibration remains one of the biggest challenges of the use of PM CEMS and therefore other compliance methods should be retained. Commenters also noted that repeated tests due to failure could result in higher total emissions from the units.

Commenters stated that the difficulty of PM CEMS calibration cannot be easily fixed using PM spiking with PS-11 and that depending on the physical design of the facility, it may be difficult to introduce PM to the exhaust stream, and the increased PM content can have negative effects on scrubbers and CCS systems. The commenters said that its use with light-scattering CEMS can also have issues due to differing PM sizes and while possible to use, PM spiking is not a panacea for solving calibration issues.

Commenters state the EPA should not reference EPRI's research into a Qualitative Aerosol Generator (QAG). The commenters said the project lost funding due to its cost and complexity, as well as the EPA's lack of response despite several attempts by EPRI to get the EPA involved in the project that sought to make PM CEMS correlations more efficient. They disagreed that the Agency should use an EPRI project the EPA never showed any support for and attempt to use that defunct project to support this rulemaking proposal.

Commenters stated units with CAM plans already in place should have a carve out to allow continued use of their CAM plan that utilizes performance indicators and operational parameters to ensure compliance with the particulate standard. They said their facility has had issues with PM CEMS in the past and they believe the use a CAM plan will ensure compliance even better than requiring PM CEMS.

Response 6: The Agency disagrees with the commenters' suggestions that PM CEMS are somehow not technically applicable for fPM measurement due to their inherent operation. PM CEMS have been available for use in compliance with this rule for over 11 years; around one-third of EGU owners or operators have chosen to rely on PM CEMS as their compliance determination method. It is unlikely that owners or operators would choose to use PM CEMS if they were unsuitable for use. Recognizing the commenters' suggestion that the tolerance for lower-level emission limits might require more attention from owners or operators, the Agency has agreed to revise the tolerance such that the value associated with a 0.015 lb/MMBtu limit will be available for use. As already mentioned, the Agency believes the adjusted tolerance will reduce if not eliminate the concern from commenters that using the former tolerance could prove problematic.

The Agency disagrees with the commenters' suggestions that the PM CEMS requirements in Appendix C be revised to include acid rain rule components such as provisional data periods, grace periods, and QA operating quarters. Such suggestions were made and rejected in the original MATS rule and are not included in this rule. As mentioned before, the compliance framework for the acid rain rule, in which source owners or operators are allowed to purchase allowances should they find their EGUs out of compliance, has no parallel in the NESHAP program. Because no allowances exist for exceedances of the emission limits for this rule, EGU owners or operators need to pay close attention to their PM CEMS and need to minimize the potential for errors or potential errors associated with PM CEMS downtime.

As already mentioned, in recognition of the potential for more difficulty in meeting existing tolerance requirements, the rule will adjust those tolerances to ease the transition for some for PM CEMS use. Also, as mentioned earlier, the pass rates from the Agency's review of correlation, RCA, and RRA reports from 36 EGUs shows projected passing rates at the rule's emission limit using the adjusted tolerances range from 78% for correlation testing, to 81% for RRAs, to 73% for RCAs; these passing rates are much greater than the commenters' reported results. Because the Agency's analysis predicts a good passing margin and because many owners or operators are expected to be able to make adjustments to their equipment to enable passing, the rule will maintain use of PM CEMS for the emission limit with the revised tolerances.

The Agency disagrees with the commenter's concern over use of spiking to develop correlations. The Agency is unaware of – and commenters did not provide – evidence of spiking not working; moreover, the Agency is unaware of individual EGUs being unable to meet their PM CEMS QA/QC requirements. The Agency notes that the three-year period between promulgation and compliance dates for this rule would be a good time for EGU owners or operators who are concerned about their familiarity with PM CEMS, issues with control devices, or effects of EGU operation to install PM CEMS early and gain valuable experience before compliance with the rule's revised emission limit is required.

The Agency disagrees with the commenters who suggest that an EPRI report on approaches for lower level PM CEMS measurements should not be mentioned. Despite the commenters' assertions, the Agency was briefed on EPRI's study but was not made aware of the conclusions, if any, from this study. Without mentioning the report, the Agency would not have been aware of the commenters' beliefs. The Agency remains interested in results of this and other similar studies, as it wants to continually advance approaches and procedures to measure emissions continuously; should the commenters share that interest, the Agency recommends the commenters build consensus to complete that work and to share the results with the Agency.

While the Agency endorses use of CAM plans in general, as mentioned earlier, the Agency finds use of PM CEMS, that provide continuous measurement of the pollutant of concern, is superior to the continuous parameter monitoring contained in most CAM plans. The rule will maintain the use of PM CEMS; as mentioned earlier, the Agency recommends EGU owners or operators who experienced or who expect to experience difficulties with PM CEMS use the period between rule promulgation and the required compliance date to gain experience with PM CEMS.

Comment 7: Commenters stated that the EPA's recommendation to require longer test runs does not remove the drawbacks of CEMS use for compliance demonstration. They said that the EPA has proposed requiring longer testing times and greater sample volume requirements; this not only introduces the chance of additional measurement issues but also poses a problem for EGUs that operate as non-baseload units and may operate infrequently. The commenters expressed concern that longer Method 5 tests could negatively impact certain FGD control devices, requiring up to nine hours of testing per unit that could result in the unit having to operate solely for testing purposes and thus increasing total air emissions. The commenters also said that some facilities have Title V permits requiring monitoring PM via CEMS on a much shorter averaging time that does not exclude testing periods and thus, MATS testing requirements could cause violations of their permits. The commenters concluded that the test sample volumes should be left to the individual facility's discretion.

Response 7: In consideration of the commenters' suggestions about lengthy duration of correlation testing, as mentioned earlier, the Agency plans to adjust from a minimum sample volume requirement to a minimum collected mass requirement of at least 3 milligrams; this change should reduce sampling times and potential impacts on control devices from operating in a less than efficient manner during high level correlation testing. EGU operational frequency is determined primarily by EGU owners and operators in conjunction with others; the Agency has little to no control over an EGU's operational schedule; whatever the duration of EGU operation, it must meet the rule's emission limitations. Therefore, EGU owners or operators should be prepared to make adjustments in operational and performance schedules as appropriate to ensure that their sources operate such that good correlations can be obtained and maintained. The Agency does not find the commenters' suggestions to reduce or eliminate necessary correlation testing for PM CEMS appropriate; such correlation testing ensures the PM CEMS yield results to demonstrate compliance with the rule. While such testing has the potential to have increased emissions over the testing period, the results of such testing are not included when assessing compliance; even if such results were included in the rule's 30-boiler operating day rolling average and if 6 runs at high load level require total durations of 12 hours for correlation testing, the periods of potential elevated emissions would comprise less than 2% of the averaging period. The Agency believes EGU owners and operators could make necessary adjustments to maintain compliance if it were required – and it is not required - for this rule during correlation testing. To the extent EGU owners or operators are subject to other applicable requirements via their title V permits, changes to this rule may or may not impact those rules; EGU owners or operators are encouraged to meet with their permitting authorities to discuss possible resolutions to what EGU owners or operators perceive to be problems with compliance with meeting other, non-Agency requirements. As mentioned earlier, the rule will change from a minimum sample volume collection to minimum collected mass requirement; this change is consistent with the commenters' suggestion to allow individual facilities the ability to determine sample volumes necessary during testing.

Comment 8: Commenters stated that sources approaching retirement should be allowed to retain quarterly stack testing for PM compliance even if required of other units as it would not be cost-effective. To be consistent with the EPA's proposed GHG rule, commenters recommend allowing sources to continue to use quarterly testing (or potentially less frequently if the unit qualifies as an LEE) provided that the unit is required to cease operation before 2032 (consistent with the proposed "immediate term" source category under the proposed GHG guidelines for existing coal-fired EGUs). Other commenters argued that units with a planned retirement date before 2035 or 2040 should be exempt from the PM CEMS requirement.

Commenters stated they agree with the EPA's proposed compliance option for units that will permanently cease burning coal by the end of 2028. They are also requesting that in lieu of quarterly emissions testing the EPA allow periodic emissions testing as part of the Part 75-required CEMS RATA test. The commenters note there has been a large decrease in electricity generation from coal units since the rule first went into effect and this trend is likely to continue. They noted this has resulted in many units, especially those facing retirement in the next decade, only operating during periods of peak electric demand, so this flexibility in the testing schedule will allow units to avoid operating solely for the purposes of emissions testing.

Commenters stated the EPA should consider that use of PM CEMS may not be appropriate for EGUs that co-fire coal with another fuel, such as biomass or natural gas, during normal operation or startup. PM CEMS and regular QA testing would incur increased testing costs for these units. They stated that some units burn natural gas during normal operation but would like to maintain the ability to burn coal, so these units would require increased coal consumption (and therefore emissions) just to complete the required calibration testing. The commenters said that in addition, the EPA should perform additional research to investigate if co-firing results in accurate CEMS measurements before enforcing a limit of 0.010 lb/MMBtu fPM during co-firing periods. They said that the EPA should consider reasonable exemptions such as allowing coal-fired units that co-fire other fuels the option to continue to use the quarterly stack-testing and CPMS options and exempting units from the requirement to use a PM CEMS if they have an fPM control technology and documented Compliance Assurance Monitoring in place. The commenters said that the EPA should also allow the option to demonstrate fPM emissions compliance during periods of PM CEMS monitor downtime via stack testing, similar to Part 75.

Commenters urged the EPA to retain the 36-month PM stack testing established under the LEE program, quarterly stack testing and CPMS options for IGCC EGUs. They said that IGCC units are built with stacks more akin to a combustion turbine and they do not have the necessary annular space to allow installation of PM CEMS. The commenters said that exposure to the elements, particularly in an area with large seasonal fluctuations, would impact the sensitivity and accuracy of the CEMS. Additionally, IGCC units do not have PM control devices for de-tuning, which is required for conducting PS-11 to establish the correlation curve. They argued that this and other factors cause certification of PM CEMS on IGCC units to be infeasible.

Commenters stated units involved with CCS projects should retain the option to use stack testing for compliance. They said that PM emissions must be measured from the CCS stack being constructed adjacent to the Young Station after CO_2 is removed. The commenters said that PM CEMS correlating testing will cause operational impacts on the CCS operations due to PM detuning for long time periods, resulting CCS operations being adversely affected or even shut down for long periods.

Commenters state the EPA should allow units that operate at capacity factors of 20% or less to continue to use quarterly stack testing to demonstrate compliance with the fPM standard and not be required to install PM CEMS. They note the EPA has proposed that the best system of emission reduction for units operating at a capacity factor of 20% or less and ceasing operation by January 1, 2035, is routine methods of operation and maintenance, and harmonization between the two rules is critical to allow operators to continue to provide reliable energy where monitoring costs will not be recouped.

Response 8: The EPA disagrees with commenters who suggest that the Agency should allow sources approaching retirement to continue to use quarterly stack testing for PM and further discussion is provided in section IV.C of the preamble. The Agency disagrees with the commenters' suggestions not to require PM CEMS for EGUs that co-fire fuels other than coal. EGU owners or operators determine their EGUs' fuel mixes; to the extent that EGU owner or operators wish to change the firing status of their EGUs, they are able to decrease coal use – while increasing other fuels – and no longer have coal-fired EGUs subject to this rule. The Agency disagrees with the commenters' suggestions to continue to allow use of quarterly stack testing or PM CPMS in co-fired EGUs; as mentioned, the Agency finds PM CEMS to be effective for compliance monitoring for such sources. While the Agency agrees EGU source owners or operators would be well advised to operate their emission control devices in a manner consistent with good engineering control practice and to collect and assess control device parameters on an ongoing basis – as required by the CAM rule – PM CEMS provide continuous measurement of the pollutant of concern, so parameter monitoring is redundant for this rule's compliance monitoring.

The Agency agrees with commenters who suggest that IGCC characteristics preclude the use of PM CEMS; moreover, IGCC emissions are more akin to those from gas- or oil-fired turbines than EGUs. Therefore, the rule will not require IGCCs to use PM CEMS for compliance purposes. Moreover, any IGCC that qualifies for LEE status under the original rule may use the 3 year testing schedule, provided it maintains emissions no greater than 50% of the fPM standard.

The Agency notes that best system of emission reduction (BSER) determinations are associated with New Source Performance Standards, not with NESHAP. Therefore, other BSER determinations have no impact on this rule. The Agency expects all EGUs, including coal- and oil-fired EGUs, except IGCCs to use PM CEMS, regardless of capacity factor.

The EPA addresses the comment about CCS and PM CEMS in section VI.C of the preamble.

Comment 9: Commenters stated that current MATS PM CEMS QA/QC requirements require artificial PM loading pursuant to Performance Specification 11. The commenters said that EGUs must intentionally turn off multiple fields of ESPs to achieve an increase in PM needed for the test and if the unit has a wet FGD, slurry injection may need to be reduced to negate any filterable PM reduction in the wet FGD.

Commenters asserted that meeting the requirements of Performance Specification 11 will be much harder with a lower fPM limit, as the tolerance interval criteria depend on the applicable emission limit. The commenters said that more Performance Specification 11 tests are likely to occur, creating additional air emissions due to detuning ESP and wet FGD control systems to obtain elevated PM conditions. They argued that the EPA should not propose changes in the MATS Rule that will extend the duration of these abnormal operation conditions.

Commenters stated that the EPA should recognize that if the MATS fPM rate is reduced to 0.010 lb/MMBtu or lower, then the frequency of RCAs will increase significantly. RCAs must be performed if a RRA does not meet specifications. The commenters said that a more stringent fPM limitation will result in more QA test failures because the pass/fail specification for tests are expressed as a percentage of the fPM limit. They said that CEMS equipment must attain “passing” results in a much narrower band due to the percentages calculated using the lower fPM limitations.

Commenters stated that the EPA should consider the consequence of lowering PM CEMS requirements on correlation testing. They said these tests will increase the time during which sources must detune control devices and significantly increase the time and cost to perform the test. The commenters said that as the fPM limitation drops lower, the frequency and duration of QA/QC tests and detune conditions will rise. Commenters advocated for minimizing intentional emissions increases as much as possible.

Response 9: The Agency agrees with commenters who suggest that PM CEMS correlation testing for the rule’s emission level will likely require more planning and adjustment than is currently needed; however, such additional attention to correlation testing should not automatically eliminate use at lower emission levels. The Agency recognizes that in order to obtain acceptable correlations, control device operation, test run duration, and acceptability criteria may need adjustment. To that extent, the rule will not require a minimum test run duration, rather, a minimum fPM catch of 3 milligrams will be specified; moreover, the rule will allow a broadened QA performance criterion equivalent to that of an emission limit of 0.015 lb/MMBtu at the rule’s emission limit of 0.010 lb/MMBtu. These revisions will ease the transition to new, as well as existing, application of PM CEMS. While no one desires lengthy periods of suboptimal emission control device operation, the Agency believes these modifications balance the need for accurate correlation information – and subsequent PM CEMS compliance readings – with short duration periods of higher fPM emissions, especially since the results of these periods when combined with emissions from normal operation are not expected to exceed the 30-boiler operating day rolling averages. Finally, the Agency’s review of a subset of initial correlation testing, RRAs, and RCAs from 36 EGUs with PM CEMS shows that passing rates using these revised criteria appear to be within expected performance.

Comment 10: Commenters noted that in the Federal Register notice, the EPA mentions meeting with commenters to discuss cost estimates for equipment and installation of PM CEMS and attributes numbers to both. Commenters suggested that there are more nuances in arriving at cost estimates, such as whether lower-cost paths or higher-end paths are taken, etc., and also observed that the EPA does not state explicitly if the cost of a PM CEMS was included in estimates for compliance costs of individual plants. Commenters noted that Jim Staudt's report (cited in the RTR Proposal and entered in the docket) quoted an estimated installed cost of $250,000 for PM CEMS. However, the costs listed for CEMS do not include costs for the annual Relative Response Audit or the 3-year (minimum) RCA required when utilizing PM CEMS as a compliance indicator. The commenters' current assessment is that this number is now dated and that a more reasonable assumption is an updated estimated installation cost of $350,000 for PM CEMS and they asserted that this increased cost can be attributed to ongoing supply chain challenges, requirements for specialized installation and significantly higher cost of project management labor. They concluded that this higher cost further supports not requiring units that fall in the Permanent Cessation category to install CEMS prior to their imminent retirement.

Commenters stated that there are some utilities that have installed PM CEMS for other reasons such as requirements in NSR consent decrees to monitor PM emissions. Commenters therefore recommend that the 2023 Proposal continue to provide sources the choice of determining compliance with the PM standards either through quarterly testing or use of CEMS.

Response 10: The Agency disagrees with the commenters' suggestions that the values supplied by other commenters lack nuance or are unclear. The Agency sought comments from all interested parties and, as described in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs*, available in the docket, the EPA calculated average costs for PM CEMS and quarterly testing from values submitted by commenters in response to the proposal's solicitation. While the average EUAC for PM CEMS exceeds the average estimated annual cost of quarterly Method 5I emission testing, the benefits associated with PM CEMS use, such as providing continuous emissions data to EGU owners or operators, regulators, or nearby community members, are not included with commenters' estimated values. As a reminder, the EPA is not obligated to choose the most cost-efficient manner for compliance demonstrations, even though cost can be an important consideration. Consistent with the discussion contained in 88 FR 24872, the Agency finds the transparency and ability to detect and correct potential control or operational problems quickly, makes PM CEMS the best choice for this rule's compliance monitoring. Even though core inflation is returning to pre-COVID levels and supply chain issues are diminishing, the Agency believes that to the extent prices are higher today, such increases occur across the board for goods and services and the Agency sees no specific distinctions for PM CEMS equipment. Finally, to the extent that consent decrees have PM CEMS or testing requirements other than those contained in this rule, the Agency recommends EGU owners or operators seek to modify such decrees so that sources are subject to one set of equivalent or most stringent requirements; should EGU owners or operators choose not to seek modification or if modification should prove not to be appropriate, then EGU owners or operators would need to meet the requirements of the consent decrees and the rule separately.

CHAPTER 4

4. Review of the Hg Emission Standards

4.1 Overview of Hg Emissions from Combustion of Coal

Comment 1: Commenters stated that the experience in the jurisdictions of the Attorneys General and Local Governments confirms that stringent limits on power-plant Hg emissions can be readily achieved at lower-than-predicted costs and thus should be adopted nationally through CAA section 112(d)(6). They said that to address widespread Hg contamination of state waterbodies, at least fourteen states have for years enforced state-based limits on power-plant Hg emissions, and nearly every one of those states has imposed a more stringent emissions limit than the proposed standards. The commenters said that these lower emissions limits have driven significant and meaningful Hg emission reductions, which have proven to be both achievable and cost-effective.

Commenters supported the proposal and said that despite significant reductions in power-plant emissions of Hg and other HAP since 2012, emissions from coal-fired power plants continue to impact their most vulnerable residents and contribute to Hg contamination of natural resources.

Commenters stated that as detailed in the 2022 States Comments, coal-fired units have capably complied with the existing standards and have done so at significantly lower cost than the EPA initially projected. They stated that this is due in part to improvements and cost reductions in pollution controls, including the ACI technology used to control Hg and similarly, coal-fired power plants have been able to achieve state-law emissions limits at reasonable cost, even where they are more stringent than the current standards.

Commenters referenced a recently completed analysis by Andover Technology Partners on the feasibility and costs of complying with lower emission limits, which found "the potential for compliance with lower PM, Hg, and HCl emission standards than in the proposed rule (https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.)." Andover Technology Partners found that lower Hg emission limits are achievable for both lignite (low rank) and non-lignite (not low rank) coal units and that significant reductions in HCl emissions are also achievable. The commenters stated that the EPA should consider this new information and determine whether additional Hg limits for non-lignite coal-firing units and acid gas limits are merited. They argued that if the EPA finds that additional Hg or acid gas limits are merited, the Agency should propose them in a future action.

Response 1: The EPA acknowledges and thanks the commenters for providing these comments. We have discussed the rationale for the final emission standards for lignite-fired EGU in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category." The EPA will continue to review emission standards and other requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years.

Comment 2: Commenters stated that the EPA notes that Minnesota has adopted Hg reduction standards that go beyond the 2012 MATS Final Rule in the reduction target and is seeking information about the cost of compliance with a more restrictive standard. (88 FR 24879). They said that Minnesota Rule 7011.0561 establishes Hg emission controls that are more stringent than the current MATS rules and that by January 1, 2018, owners, or operators of a coal-fired EGU in Minnesota with a nameplate electricity generation capacity greater than 100 MW were required to control Hg such that at least 90% of the Hg present in the fuel is captured and not emitted or demonstrate that the unit emits no more than 0.8 lb Hg per TBtu. The commenters said that Minnesota utilities have opted to comply with the emissions rate form of the standard primarily because of their use of Hg CEMs. They said that emissions data is required by Minn. R. 7011.0561 subp. 6.J. to be reduced to 30-day averages for comparison to this standard.

Response 2: The EPA acknowledges and thanks the commenters for providing these comments. The EPA did not propose to change the Hg emission standard for affected sources firing non-lignite coals (such as the coal-fired EGUs in Minnesota that fire primarily subbituminous coal). We have discussed the rationale for the final emission standards in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category." The EPA will continue to review emission standards and other requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years.

4.2 Hg Emission Reductions Since Promulgation of the 2012 MATS Final Rule

4.2.1 Hg Emissions From Coal-Fired EGUs in 2021

Comment 1: Commenters stated that the MATS rule currently requires a less stringent Hg emission standard for lignite-burning plants than is required for other coal-fired plants owing to earlier questions of the performance and cost effectiveness of controls on lignite-burning plants. As a result, lignite-burning plants are emitting "beyond their weight." The 2023 Proposal indicates that 16 of the top 20 Hg-emitting electric power plants use lignite as a fuel. Taken as a whole, the 2023 Proposal states that in 2021 lignite burning plants emitted almost 30% of the Hg from the power generating sector while producing only 7% of the country's electricity.

Commenters stated that the [2012] MATS rule successfully reduced emissions of Hg by coal- and oil-fired electric power plants. As a result of MATS and other changes in the industry, emissions of Hg from the electricity-generating industry, once the largest anthropogenic source of Hg emissions, have fallen from pre-MATS levels of 29 tpy to less than 3 tpy in 2021.

Response 1: The EPA acknowledges and thanks the commenters for providing these comments. We agree that Hg emissions from coal- and oil-fired EGUs have dropped by 90+% since promulgation of the MATS rule in 2012 (as compared to pre-MATS emissions). We also agree that lignite-fired EGUs emit a disproportionate amount of Hg – emitting 30% of all Hg emissions from affected sources while generating 7% of megawatt-hr. We have discussed the rationale for the final emission standards for lignite-fired EGU in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 2: Commenters stated that the EPA must revise the Hg limits to no higher than 0.15 lb/TBtu for not-low-rank coal units and no higher than 0.5 lb/TBtu for low-rank coal units based on developments in practices, processes, and control technologies. They stated that the 2021 Andover Technology Partners report notes advances in control technologies that support stronger Hg standards like more advanced activated carbons with higher capture at lower injection rates and carbons that are tolerant of flue gas species. The commenters said that these developments have made over 90% Hg capture possible under virtually any circumstances and other advances in fuel additives, scrubber operation, scrubber systems like Gore Technology, and scrubber additives provide additional ways to reduce Hg emissions, and further support stronger Hg limits for all coal plants.

Response 2: The EPA acknowledges and thanks the commenters for providing these comments. We have taken these comments and the referenced information into consideration when establishing the final emission standards. The Agency did not propose to revise the Hg emission standard for "not-low-rank coal units" (*i.e.,* those EGUs that are firing on a coal fuel other than lignite) in the 2023 Proposal (88 FR 24879). The EPA will continue to review emission standards and other requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. We have discussed the rationale for the final emission standards in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

4.2.2 Limited CAA Section 114 Request

Comment 1: Commenters stated that the dataset collected by the CAA section 114 request consisted of 17 units each submitting two, one-week periods of data and associated operational data preselected by the EPA. They said that seven of these units were in North Dakota, eight were in Texas, and two were in Mississippi and of the North Dakota units, only one reported burning only lignite coal, the rest reported burning primarily refined coal, and one reported burning no lignite coal. The commenters said that station reported co-firing 35.6% natural gas and 64.4% refined coal and the data was also similar in Texas and Mississippi where only three of 12 units reported using only lignite coal and five of the 12 reported using greater than 75% subbituminous coal (Table-7 in the 2023 Proposal). Commenters stated that if the EPA's intent was to assess lignite-fired units, then the units evaluated should burn lignite, not refined coal, subbituminous coal or natural gas.

Response 1: According to fuel use information supplied to EIA (on form 923), 13 of 22 EGUs that were designed (and permitted) to burn lignite utilized "refined coal" to some extent in 2021, as summarized in Table 7 in the proposal preamble (88 FR 24878). EIA form 923 does not specify the type of coal that is "refined" when reporting boiler or generator fuel use. For this technology review, the EPA has assumed that the facilities have utilized "refined lignite," as reported in fuel receipts on EIA form 923.

Regarding the commenters claim that, if the EPA's intent was to assess lignite-fired units, then the units evaluated should burn lignite, not refined coal, subbituminous coal or natural gas. The EPA intent was to evaluate the Hg emission control performance of units that are permitted to burn lignite (and thus are part of the subcategory that has been subject to an emission standard of

4.0 lb/TBtu). The use of "refined coal" or co-firing with other fuels such as natural gas or subbituminous coal are considered to be Hg control options for a unit with an emission standard of 4.0 lb/TBtu, which was based on the use of lignite as its fuel.

Comment 2: Commenters said they found it curious that the EPA requested information for only select time periods in the CAA section 114 request. They said that upon further study, it appears that the EPA hand-picked these time periods, possibly to showcase low and high Hg emissions ranges. Upon study of the Young Station's operational data for these time periods, it is highly likely that these ranges showcase the variability of Hg content in lignite instead different control scenarios. The commenters stated that for this reason, they specifically warned the EPA in the CAA section 114 response that the time periods requested are not representative of emissions achievable on a 30-day rolling basis. Nonetheless, the EPA relied on these data and operational information as representative.

Commenters reiterated notes from their CAA section 114 ICR response, stating that their Unit 1 and 2 Hg emissions and operational data for weeks 1 and 2 are not representative of emissions achievable on a 30-day rolling basis for the units, nor are the weeks comparable to one other. They said the significant differences between the two weeks are:

- Most importantly, lignite coal quality varied significantly, including variability of Hg concentrations. Coal quality between the two weeks differed based on our analysis of the sorbent and PAC applied as compared to the Hg emission rates, as discussed below.
- Unit 1 - week 1 and week 2 used different Hg control equipment and halogen manufacturers.
- Unit 2 - week 1 and week 2 used the CCS system, which is no longer operating and was replaced by the modified NALCO system in November 2021.
- Unit operation varied. Week 1 included low-load operation conditions, which were not present during week 2. Hg emissions are reported as higher at lower loads.

Commenters stated that the data provided in the response to the CAA section 114 requests was insufficient to inform the EPA of any meaningful Hg information. This data would not be scientifically useful for setting a new Hg standard and the EPA requested information which sources did not have (*e.g.*, inlet Hg monitoring data).

Commenters stated that in addition, a limited 7-day data set does not account for fuel quality variability. While commenters said they do not test inlet Hg concentrations, they said they do have coal analysis of random samples taken from coal conveyor belt as the coal storage silos are filled. They said a maximum of six samples are collected daily and analyzed for proximate analysis and while these samples do not include Hg concentrations, but do show considerable variation in ash content, Btu value, and other constituents.

Commenters said that units are unique and referred to data from two EGUs identified as "Unit 1" and "Unit 2". They said operators utilize the same Hg control strategies for the two units. However, Unit 2 consistently has higher Hg emissions in comparison to Unit 1. The differences in Hg emissions are impacted by operating characteristics of the units, such as varying load levels/load swings, unit size, wet scrubber design differences, and ductwork configuration. They said inconsistent hourly emissions and Hg system data illustrate these differences and should assist the EPA in understanding unit variability in general and with respect to Unit 1 and Unit 2 operations. For this reason, the responsive weekly data cannot reliably or reasonably support changes in permitted emission rates or permit conditions because this limited data set is not representative of current operations, fuel variability, and uncertainty in fuel quality. They said these factors all contribute to differences in emission characteristics. The commenters stated that even though week 1 and week 2 are not comparable weeks, commenters reviewed the data regarding PAC used and sorbent used in their possession. Week 1 reported lower Hg emissions in comparison to week 2 values. However, commenters did not inject any PAC during week 1. They injected 1.9 ppm of sorbent. Commenters believe that CCS did not inject more than 6 ppm of halogen, although no documentation of that quantity is available. Lower Hg emissions were likely the result of a weekly coal batch that was lower in Hg content during week 1. In comparison, commenters injected PAC and halogen during week 2. Hg emissions were higher, likely due to low load operation during that week and suspected coal quality variations.

Commenters further stated that conversely, Unit 2 week 1 PAC was injected at a higher rate than week 2. Week 1 had lower CO_2 during most of this 7-day period and yet was able to maintain a Hg emission rate around 2.17 lb/TBtu, while Hg emissions during week 2 were around 3.0 lb/TBtu with normal-high load operation and CO_2 concentrations averaging 10%. Commenters attributed the inability to correlate the Hg emissions with the control system data to variability of coal quality and lack of information regarding operation of the halogen system during the pre-November 2021 operating period. In other words, the lack of Hg control information for Unit 2 during week 1 prevents commenters from drawing a conclusion regarding the variables that impacted Hg emissions that week.

Response 2: The EPA did not rely exclusively (or even mostly) on information obtained from the CAA section 114 information request. The EPA relied on a variety of data sources in developing the proposed and final Hg emission standards for lignite-fired EGUs. These data included historical coal analyses, the results from demonstration tests (including those conducted by DOE and others), publicly available Hg emissions data that is reported to the EPA for compliance demonstration, and data and information obtained from owners/operators of lignite-fired EGUs from EPA's limited CAA section 114 information survey. We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 3: Commenters stated that the EPA did not include data for the Coyote Station in the limited Information Collection Request, even though Coyote Station is the only North Dakota lignite-fired EGU that utilizes halogenated Powdered Activated Carbon sorbent to exclusively control Hg, the very type of sorbent that the EPA suggests in its proposal ought to be used by lignite-fired EGUs to lower their Hg emissions to the proposed level.

Response 3: The EPA relied on a variety of data sources in developing proposed Hg emission standards for EGUs burning lignite. This included historical coal analyses, results from demonstration tests (including those conducted by DOE and others), publicly available Hg emissions data, and data and information obtained from owners/operators of lignite-fired EGUs from EPA's CAA section 114 information survey. The EPA conducted a limited (*i.e.*, from 9 or fewer entities) CAA section 114 information survey and selected the entities for the survey to maximize amount of data. The EPA was unaware of the specific control technologies used at the various sources (which was one of the objectives of the survey) and, therefore did not know that Coyote Station is the only North Dakota lignite-fired EGU utilizing exclusively halogen PAC to control Hg. We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 4: Commenters argued that against their direction, the EPA inappropriately used commenters' data in the 2023 Technology Review memo, without any caveats, to manufacture a Hg baseline. They said the Young Station data are not reliable for use in the EPA's database and the EPA cannot engage in data selectivity to arrive at a skewed end result. They said the EPA should reconsider the assumptions and data used in this analysis and develop a reasonable baseline and evaluation of the feasibility of lignite units to achieve a lower Hg limit.

Commenters stated that the EPA disregarded information provided by commenters regarding the actual Hg content of the lignite fired in its units and instead determined that it was appropriate to use an assumed Hg content. Commenters stated that the EPA provided no explanation for why site-specific information that it was provided was not used in the EPA's analysis. Commenters stated that the reliance on assumptions over available, site-specific data has resulted in significant flaws in the EPA's assessment of current control efficiencies of lignite-fired EGUs, the ability of these units to achieve a significantly lower Hg limit, and the costs associated with this new limit.

Response 4: The EPA relied on a variety of data sources in developing proposed Hg emission standards for EGUs burning lignite. The EPA did not rely exclusively on information collected in the limited CAA section 114 survey. The EPA relied on historical coal analyses, results from demonstration tests (including those conducted by DOE and others), and publicly available Hg emissions data, to supplement the data and information obtained from owners/operators of lignite-fired EGUs from EPA's CAA section 114 information survey. We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 5: Commenters stated that the EPA's inclusion of Limestone Units 1 and 2 and Martin Lake Units 1, 2 and 3 in its lignite-fired EGU analysis is inappropriate. These units had begun or had already completed the process of transitioning to non-lignite fuel prior to the 2023 Proposal. The EPA was aware of these transitions and did not even issue a CAA section 114 request for Limestone Units 1 and 2. During transition, these units are burning a different mix of fuel, and upon completion of these units' transition, they will no longer be part of the lignite EGU subcategory at all. Commenters stated that as a result, these sources cannot be reflective of any Hg controls that may have developed within the lignite subcategory, and the EPA must re-perform its analysis after removing these units.

Response 5: The EPA relied on a variety of data sources in developing proposed Hg emission standards for EGUs burning lignite. The EPA did not rely exclusively on information collected in the limited CAA section 114 survey. In their response to the EPA's CAA section 114 survey, the owner/operator of the Martin Lake EGUs indicated that they have "historically fired a blend of lignite and western coal" and did not state that they were in the process of transitioning to non-lignite fuel. In late 2023, Limestone Units 1 & 2 were still permitted as lignite-fired EGUs and subject to a Hg emission limit of 4.0 lb/TBtu, despite firing on nearly 100% non-lignite fuel. These sources are, therefore, still part of the subcategory. In these cases, the use of non-lignite fuel must be viewed as a Hg emission control strategy – since CAA section 112(d)(2) states that "[e]missions standards promulgated under this subsection and applicable to new or existing sources of hazardous air pollutants shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies, through application of measures, processes, methods, systems or techniques including, but not limited to, measures which—(A)reduce the volume of, or eliminate emissions of, such pollutants through process changes, **substitution of materials** or other modifications," [emphasis added]. In a related context, in *U.S. Sugar Corp. v. EPA*, the D.C. Circuit held that the EPA could not exclude unusually high performing units within a subcategory from the Agency's determination of MACT floor standards for a subcategory pursuant to CAA section 112(d)(3). 830 F.3d 579, 631-32 (D.C. Cir. 2016) (finding *"an unusually high-performing source should be considered[,]" in determining MACT floors for a subcategory, and that "its performance suggests that a more stringent MACT standard is appropriate."*). While the technology review at issue here is a separate and distinct analysis from the MACT floor setting requirements at issue in *U.S. Sugar v. EPA*, similarly here the EPA finds it is appropriate to consider emissions from any units that are permitted to burn lignite and are therefore subject to the prior Hg emission standard of 4.0 lb/TBtu and are part of the lignite-fired EGU subcategory, for the purposes of determining whether more stringent standards are appropriate under a technology review.

4.3 CAA Section 112(d)(6) Technology Review of the Hg Standards

Comment 1: Commenters stated that the technology-based review conducted under CAA section 112(d)(6) need not account for any information learned during the residual risk review under CAA section 112(f)(2), unless that information pertains to the statutory factors relevant to the CAA section 112(d)(6) review, such as the cost of achieving maximal emission reductions. Nor does CAA section 112(d)(6) require the EPA to find unacceptable risk or the absence of an ample margin of safety as a prerequisite to determining that it is necessary to strengthen standards. Where achievable at reasonable cost, the EPA must secure the deepest HAP reductions possible, apart from any identified health or environmental impacts.

Response 1: The EPA agrees with commenters that the CAA section 112(d)(6) technology review and CAA section 112(f)(2) residual risk review are distinct analyses. *See Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 5 (D.C. Cir. 2015). As the EPA discusses elsewhere throughout the record for this rulemaking, cost is one of several factors the EPA considers in determining whether updated standards are necessary under the technology review.

4.3.1 Review of the Hg Emission Standard for Non-Lignite-Fired EGUs

Comment 1: Commenters expressed agreement with the EPA's proposal to retain the Hg emission standard of 1.2 lb/TBtu for non-lignite-fired EGU units. The EPA based this decision primarily on the fact it lacks detailed information about control configurations and efficiencies. They said the Agency also did not identify any developments in practices, processes, and control technologies that would justify revising the Hg standard for non-lignite-fired EGUs under CAA section 112(d)(6).

Commenters stated that available Hg emissions do not provide a basis for revising the current Hg standard. They said the EPA reports bituminous coal-fired and subbituminous coal-fired EGUs achieve an average annual Hg rate of 0.4 lb/TBtu and 0.6 lb/TBtu, respectively. The commenters said, however, compliance under MATS is based on neither an average rate among EGUs, nor on an annual rate, rather compliance is based on 30-day rolling rate for each EGU. They said, accordingly, the Agency's data about average annual performance is not relevant to the standard at issue. They argued that these data do not account for the variability in Hg emission rates between EGUs and on day-to-day and month-to-month basis for each EGU. The commenters stated that variability is driven by myriad factors, and strongly supported retaining the current Hg standard for non-lignite coal-fired EGUs.

Commenters stated that their attached NRECA technical evaluation contains data that support retaining the current Hg standard. Indeed, even looking at annual average rates, analyses of the 2018 data show that the sum of the annual average with the standard deviation, which is the range of variability in the data, approaches the current 1.2 lb/TBtu standard. In addition, commenters offered the following observations that highlight the vast variability in factors that affect Hg emissions – first, the variability in Hg content of non-lignite coals, for both bituminous and subbituminous coals, is considerably broader than the EPA suggests in the 2023 Proposed Rule.

Commenters stated that secondly, the variability in process conditions for Hg removal (*i.e.,* Hg content in coal, sorbent composition, sorbent injection rates, co-benefits, and re-emission) is also broad and does not support further lowering Hg standard for non-lignite-fired EGUs. Sorbent injection plays a critical role in removing Hg emissions from bituminous and subbituminous coal-fired EGUs. They said that the EPA correctly points out that increasing sorbent injection rates generally increases Hg removal but with diminishing returns as more sorbent is added. For example, research tests at Ameren's Labadie Unit 3 explored the effectiveness of conventional activated carbon, brominated active carbon, and conventional activated carbon for Powder River Basin subbituminous coal. Results show that increasing sorbent rates of any of the three materials could only reach a control maximum of 90% removal. Consequently, it is not at all assured that an EGU that relies on sorbent injection for Hg control could increase its Hg removal efficiency simply by increasing the amount of sorbent used.

Commenters stated that the co-benefits of SCRs and FGDs are highly variable. They said they are unaware of actions that could be taken to improve the co-benefit removal efficiency of particular equipment installed at a particular EGU. Emission control efficiencies are further potentially undermined by re-emission of Hg from wet FGD. Uncaptured Hg in wet FGD may be re-released in solution during the blowdown stage, precipitated and released as an unintended byproduct, or reduced from an oxidized state and re-enter the flue gas. Upsets in wet FGD can also reduce the collection efficiency and re-emit Hg emissions.

Commenters stated that Hg control efficiencies are further impacted by variability in electricity loads. They said that an in-plant study, for example, found that loss of oxidation/reduction potential control, known to vary over load cycles, results in Hg re-emissions. They argued that little, if anything, can be done to mitigate control efficiency variability due to load variability.

Commenters acknowledged that the EPA has solicited comments on its proposed decision not to revise the Hg standard for non-lignite-fired EGUs and requested information that could possibly support a revised standard. Commenters are unaware and do not believe such information exists. In any event, if additional information submitted to EPA leads the Agency to consider a revised Hg standard for non-lignite coal-fired EGUs, commenters respectfully suggested (and requested) that the EPA must first propose such a revised standard in a Supplemental Notice of Proposed Rulemaking or a separate Notice of Proposed Rulemaking and take comment on such a proposed standard before adopting it.

Response 1: The Agency did not propose to revise the Hg emission standard for "not-low-rank coal units" (*i.e.*, those EGUs that are firing on a coal fuel other than lignite) in the 2023 proposal (88 FR 24879). The EPA will continue to review emission standards and other requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If, in the technology review, the Agency determines that modification of any emission standards is warranted, it will first propose revision to the standards and solicit comment on those proposed revisions.

Comment 2: Commenters urged the EPA to adopt an even more stringent standard than the existing 1.2 lb/TBtu standard for non-lignite-fired power plants, similar to the lower emissions limits that many states have been implementing for years. Commenters noted that state experience demonstrates that lower emissions limits— in particular 0.6 lb/TBtu—are being met using proven and affordable control technologies. Data from units consuming not-low-rank coal (*i.e.,* non-lignite) shows that fully 80% of all such units are capable of achieving 90% Hg emissions capture or better and emissions rates of 0.65 lb/TBtu or less. Commenters stated that if 80% of such units are capable of achieving—and indeed exceeding—0.65 lb/TBtu, it is plainly a technologically feasible standard. Commenters recognized the EPA's concern about assessing the costs of meeting such a lower Hg standard without having collected CAA section 114 data on the type and injection rates of sorbents and chemical additives. Commenters stated that the EPA should be able to evaluate those costs using other available data sources. Commenters thus urged the EPA to adopt a more stringent standard for non-lignite units of at least 0.65 lb/TBtu pursuant to its CAA section 112(d)(6) review.

Commenters stated that a Hg standard of 0.3 lb/TBtu could be complied with at a modest cost to most units, and no cost for some units. The cost would not exceed 1 mill/kWh and would likely be much less. Units with FFs would have very little, if any, cost increase.

Commenters stated that EGUs burning higher rank coals (non-lignite coals) may have opportunities to reduce Hg emissions through use of a SCR system installed primarily for NO_x control (*e.g.,* under the EPA's "Good Neighbor Plan"). While these systems do not directly capture Hg, they can, under the right conditions, enhance the oxidation of Hg^0 in the flue gas for increased Hg removal in a downstream PM control device or in a wet FGD scrubber. Commenters recommended that the EPA should lower the standard to 0.3-0.7 lb Hg/TBtu for higher rank coals.

Response 2: The Agency did not propose to revise the Hg emission standard for "not-low-rank coal units" (*i.e.*, those EGUs that are firing on a coal fuel other than lignite) in the 2023 proposal (88 FR 24879). The EPA will continue to review emission standards and other requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If, in the technology review, the Agency determines that modification of any emission standards is warranted, it will first propose revision to the standards and solicit comment on those proposed revisions.

Comment 3: Commenters stated that to be consistent with the EPA's obligation to consider maximum achievable HAP emission reduction and costs, the EPA should review the latest data to ensure the Agency is selecting the appropriate level of stringency for its standards.

Response 3: The EPA acknowledges and appreciates this comment.

4.3.2 Review of the Hg Emission Standard for Lignite-Fired EGUs

Comment 1: Commenters supported the EPA's proposed 1.2 lb/TBtu Hg emissions limit for lignite coal-fired units, which represents a starting point that can and should be revisited and strengthened as new compliance data becomes available. The proposed limit is the same Hg emissions limit that non-lignite-fired units already meet—and that many of those units regularly exceed. The commenters said that applying the experience of non-lignite units, the EPA correctly observes that available controls and methods of operation, especially ACI systems, will allow lignite-fired units to meet the same Hg standard that is being met by units firing on non-lignite coal supply and that the costs of doing so are reasonable. They said that the Agency appropriately relies on the beyond-the-floor costs from the 2012 MATS Final Rule, the injection rates reported in the CAA section 114 survey results, and the calculated cost effectiveness of using ACI controls. The commenters stated that the EPA has also used a conservative method of determining the cost of injecting non-brominated ACI, and, further, correctly recognizes that even with differences (and similarities) in feedstocks, lignite-fired units simply are not yet deploying any of the most effective control technologies that are already in use and proven at non-lignite-fired power plants. As the EPA notes, the projected cost of the revised lignite Hg standard, $8,703 per lb of Hg removed, is significantly lower than the cost it has previously found acceptable—both in calculating the existing Hg standards and in other rulemakings.

Commenters stated that given the experience of many jurisdictions in implementing more stringent Hg standards and the EPA's robust analysis in the 2023 Proposal, the determination that it is "necessary" under CAA section 112(d)(6) to reduce the emissions limit for lignite-fired units to 1.2 lb/TBtu is well-supported—especially since proven, cost-effective technology is so readily available. Further, because that emissions limit is the existing standard for non-lignite sources, the EPA correctly applies the known cost effectiveness and usability of ACI and other technologies in non-lignite units to inform its decision to propose the same standard for lignite units. While the commenters supported the EPA's adoption of the proposed 1.2 lb/TBtu limit, commenters stated they would also support further Hg emission reductions by lignite units below that limit and encourage the EPA to collect information on those units' compliance with the proposed limit in order to support possible future strengthening of the standard.

Response 1: The EPA acknowledges and appreciates these comments.

Comment 2: Commenters found that the EPA's proposal to reduce the Hg limit for lignite-fired EGUs is well supported. Additionally, commenters recommended that the EPA consider a lower 1.0 lb/TBtu annual limit. They said that in comparison to the proposed limit, the lower limit would cut an additional 135 lb of Hg emissions annually, reducing the total emissions from these facilities to 675 lb/year.

Commenters stated that tighter emission limits for lignite-fired EGUs will result in Hg emission reductions across national park ecosystems impacted by lignite-fired EGU emission sources in North Dakota, Texas, and Mississippi. They said that using insects (dragonfly larvae) as indicators of Hg risk, their analysis finds that greater than three-fourths of the dragonfly Hg data across 15 national parks in relative proximity to the lignite-fired EGUs subject to MATS fall into the moderate or high (100-700 ng/g dw) impairment categories for potential Hg risk. Additionally, they said that an index of moderate impairment or higher suggests that Hg concentrations in top predator fish species may exceed the EPA benchmark for protection of human health, threatening them mandate to provide visitor enjoyment opportunities and keep resources unimpaired for future generations. The commenters said that Hg in fish data from parks near the lignite-fired EGUs, including Theodore Roosevelt (North Dakota), Voyageurs (Minnesota), and Big Thicket (Texas) National Parks, Buffalo National River (Arkansas), and Jean Lafitte National Historical Park and Preserve (Louisiana) illustrate the presence of Hg in fish in these parks. The commenters said that elevated fish Hg concentrations are particularly evident at Voyageurs and Big Thicket national parks.

Commenters cited reports for both Hg and non-Hg monitoring in national parks. Commenters presented Hg monitoring data in national parks that indicate more than two-thirds of dragonfly larvae across 135 national parks fall into the moderate or higher impairment categories. The commenters said that data on the top predator fish species may exceed the EPA benchmark for protection of human health a cited a study by Eagles-Smith et al. Commenters said that Justice 40 communities were disproportionately burdened by this legacy contaminant across the landscape. Commenters cited significant improvements in concentrations measured at national parks between 2011 and 2020 and attributed these improvements to MATS. Commenters said the National Parks Service is concerned by levels of Hg in fish that exceed human and wildlife health thresholds, and the deleterious effects Hg may be having in fish in several western national parks. Commenters said the strengthening of MATS would likely lessen the impact of this pollutant on ecological integrity and visitor experiences across the national park system.

Response 2: The EPA acknowledges and appreciates these comments. The EPA proposed (and is finalizing in this action) to revise the Hg emission standard for EGUs in the lignite-fired subcategory from an emission limit of 4.0 lb/TBtu to an emission limit of 1.2 lb/TBtu. However, the EPA has not proposed any revisions to the MATS emission standards under the CAA section 112(f)(2) risk review. Rather, the revisions were proposed in response to a CAA section 112(d)(6) technology review. CAA section 112(d)(6) requires that the EPA review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards at least every 8 years.

Comment 3: Commenters stated that according to the 2023 Technology Review memo, the EPA based its proposed change to the Hg emissions limits on information provided routinely to the EPA and to the EIA, information that the EPA solicited under CAA section 114, 42 U.S.C. 7414(a), in May 2021, and any "additional information was obtained from the EPA's NEEDS database." (2023 Technology Review memo at 18). Commenters stated that the EPA has multiple unsupported contentions and fails to cite some of its foundational contentions. For example, the EPA states that the information from the EIA and the CAA section 114 survey "showed developments that demonstrate that lignite-fired EGUs can achieve a Hg emission rate that is much lower than the current standard, and that there are cost-effective control technologies and methods of operation that are available to achieve a more stringent standard." 88 FR 24857. Commenters stated that the record shows that available information generally related to fuel consumption does not, by itself, show the new standard is achievable.

Commenters stated that while the EPA includes a summary of the CAA section 114 survey responses in Table 9 of the 2023 Technology Review memo, there are no citations to docket document identification numbers for the survey and responses or an explanation of the methodology of the CAA section 114 survey requests. For example, the EPA does not provide a comprehensive list of which lignite-fired EGUs were surveyed. Nor does the EPA provide an explanation of which lignite-fired EGUs it chose to survey. (2023 Technology Review memo at 13-14; 88 FR 24876: "EPA solicited information related to Hg emissions and Hg control technologies from certain lignite-fired EGUs to inform this CAA section 112(d)(6) technology review"). Commenters stated that the EPA does not explain why it supplemented the data from these "certain lignite-fired EGUs" with NEEDS data. *Id*.

Response 3: The EPA did not rely exclusively (or even mostly) on information obtained from the CAA section 114 information request. The EPA relied on a variety of data sources in developing the proposed Hg emission standards for EGUs burning lignite. This included historical coal analyses, results from demonstration tests (including those conducted by DOE and others), publicly available Hg emissions data, and data and information obtained from owners/operators of lignite-fired EGUs from EPA's limited CAA section 114 information survey. The cover letters, correspondence, and all submitted information for EPA's limited CAA section 114 were available in the rulemaking docket and are easily found using a simple keyword search. We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 4: Commenters expressed concern that the EPA is proposing a substantial reduction in the Hg emission standard based on inaccurate data and a flawed evaluation of the Hg control capabilities of lignite-fired EGUs. They said first, the EPA's CAA section 114 request was very limited considering the amount of data available and, in many cases, the EPA disregarded the very information that was submitted in the responses. The commenters said that certain units burning large percentages of subbituminous coal have transitioned or are in the process of transitioning to the non-lignite subcategory, and such units should have been removed from the EPA's evaluation. They said specifically, the EPA's evaluation — encompassing a review of 22 EGUs "that were designed to burn lignite utilized refined coal to some extent in 2021" (EPA Technical Memo, PDF p. 18) — contains major flaws, some of which are summarized below:

- The majority of these EGUs do not primarily burn all lignite coal. As denoted in Table 10 of the EPA's technical memo, the evaluation of 22 EGUs includes only four EGUs that burn 99.7% or more lignite coal, with the other 18 EGUs burning only 37.6% or less lignite coal.
- It is unclear whether the Hg emissions that the Agency reviewed for the 22 EGUs were from units operating at full or partial load.
- Rather than using actual sampled data of lignite Hg concentrations that had been provided in the CAA section 114 responses, the EPA used IPM data to assign inlet Hg concentrations to various lignite-fired EGUs.

Response 4: The EPA disagrees that the proposed changes are based on inaccurate data and a flawed evaluation of the Hg control capabilities of lignite-fired EGUs. We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category." All EGUs examined for the proposal were permitted as lignite-fired units. To review that emission standard, the EPA evaluated the 2021 performance of lignite-fired EGUs (including those permitted to burn lignite but utilized significant amounts of subbituminous coal or natural gas in 2021). Many of the EGUs used "refined coal." Refined coal is typically produced by mixing proprietary additives to feedstock coal to help capture emissions when the coal is burned. EIA form 923 does not specify the rank of coal that is "refined" in boiler or generator fuel data. For the technology review, the EPA assumed that facilities reporting the use of refined coal have utilized "refined lignite," which was confirmed in EIA form 923 fuel receipts and costs and the EPA received no comments challenging that specific assumption. The Hg emission standards under MATS must be met based on a rolling 30-day rolling average and apply whether the affected source is operating at full or partial load. In any case, operational data for EGUs are available through the EPA's Clean Air Markets Program Data (CAMPD) at https://campd.epa.gov/. The EPA has also discussed adjustments to assumed coal Hg content elsewhere in this document, in the 2024 Technical Memo and in the preamble for this final action.

Comment 5: Commenters stated that the lignite units evaluated that are equipped with SCR are not representative of North Dakota lignite units. Although SCR has been demonstrated on the types of lignite found in other parts of the country, it is not in North Dakota. They said, in fact, North Dakota lignite differs substantially because it has a different chemical makeup that contains a much higher concentration of alkali metals (*e.g.,* sodium and potassium) that render the catalyst ineffective and unable to operate for more than a short period of time, prohibiting any cost-effective application of SCR. The commenters further said the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 µm. As a vapor or as a very small particle, the sodium will reach the SCR and plug the pores of the catalyst, which is the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive.

Response 5: The EPA acknowledges this comment; however, the Agency did not propose to require the use of SCR on EGUs firing North Dakota lignite or on any other EGU in the April 2023 proposal.

Comment 6: Commenters stated that the EPA also does not address boiler design in the Technical Memo, despite that during the original rule development, boiler design had a large bearing on actual Hg emissions. To illustrate, the commenters said that the EPA explained that circulating fluidized bed boilers as compared to pulverized coal boilers had much lower emissions: [T]here are other EGUs in this subcategory that are circulating fluidized bed combustion units which do not meet the height-to-depth ratio parameters in the proposed rule, nor are they anything like the pulverized coal EGUs we initially identified as having the 3.82 height-to-depth ratio… they were particularly concerned about the circulating fluidized bed units because other circulating fluidized bed units are well represented among the best performing EGUs for Hg in the =8,300 Btu/lb subcategory, but the circulating fluidized bed units burning low rank virgin coal are not achieving the same levels of Hg emissions control. The commenter said including the best performing circulating fluidized bed units from the other subcategory in the low rank virgin coal subcategory would likely lead to a Hg standard as stringent as the standard for EGUs in the =8,300 Btu/lb subcategory because the circulating fluidized bed units from the other subcategory would be used to establish the floor.

Response 6: We did not address boiler design in the April 2023 proposal because, in the final MATS rule preamble (77 FR 9378-9), we explained that "we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned … low rank virgin coal … that causes the disparity in Hg emissions." And, we further noted that "[a]fter fully considering the available information, including the comments received, we have concluded that it is appropriate to continue to base the subcategory definitions, at least in part, on whether the EGUs were designed to burn and, in fact, did burn low rank virgin coal, but that it is not appropriate to continue to use the height-to-depth ratio criteria because that approach would potentially exclude EGUs we identified as having different Hg emission characteristics and include EGUs that did not have different emissions characteristics."

Comment 7: Commenters stated that in the calculation for 2021 Hg emissions (EPA's Table-8 in the 2023 Proposal), the EPA used a value of 7.76 lb/TBtu as the estimated inlet Hg value. Based on this value, the EPA calculated the necessary removal percentage to comply with a 1.2 lb/TBtu limit as 84.5%. Commenters believed this value is low based on Hg data obtained from the local mine which exclusively supplies lignite coal to the Antelope Valley and Leland Olds Stations.

They said that when considering all the drill core data available from the mine, the maximum value of Hg in the coal is 40.95 lb/TBtu. This value is over five times the value EPA used in its calculation of Table-8 in its preamble to the 2023 Proposal. Furthermore, the average value in the coal data is 11.33 lb/TBtu which is nearly 1.5 times the inlet value of 7.76 lb/TBtu that the EPA used. Based on the maximum value, the Antelope Valley Station and the Leland Olds Station would need to remove 97% of the Hg to reach a limit of 1.2 lb/TBtu. Similarly, at an inlet of 11.33 lb/TBtu the remove needed equals 89.4%. Commenters strongly requested that the EPA reevaluate the inlet Hg content of lignite fuels using actual data provided in the CAA section 114 responses.

Response 7: We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category." The EPA has evaluated additional sources of information and has adjusted assumed Hg inlet concentrations for all sources.

Comment 8: Commenters stated that the EPA also generally claims to have reviewed "available literature and other studies and available information" to assert that there are developments in practice, process, or control technology that justify the 2023 Proposal (88 FR 24880). Commenters stated that this literature fails to adequately distinguish between lignite and subbituminous coals and further, unlike the 2012 MATS Final Rule, none of the reviewed materials were named, specified, or provided, making the alleged basis for the 2023 Proposal unavailable for public scrutiny, verification, or meaningful comment in violation of the APA. They argued that the only explicit information that the EPA shared was that one commenter had informed them that costs of compliance for end users has decreased over time "due to the many options that are available to control Hg emissions . . . and a robust industry of technology suppliers that drive innovation through internal research and development" and another commenter stated that "ACI2 systems operate more reliably, and users utilize technology to improve dispersion of sorbents in flue gas for better performance." (88 FR 24867; 24880). The commenters said that while the EPA provides document identification numbers (EPA-HQ-OAR-2018-0794-4940 and EPA-HQ-OAR-2018-0794-1171), these comments do not provide empirical evidence supporting these statements. Commenters stated that the 2023 Technology Review memo provides unsubstantiated statements that inhibit the EPA from providing a reasonable explanation for finding that there are technological developments.

Commenters stated that the EPA asserts that the 2020 Final Action did not consider developments in the cost and effectiveness of the proven control technologies and did not evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs to determine whether revising the MACT standards was warranted (2023 Technology Review memo at 2). They said, however, the 2020 RTR did consider the current performance of existing technology as it noted EGUs were in compliance. EPA-HQ-OAR-2018-0794-0015 (2018 Technology Review memo) at 10 ("This review identified no developments…in practices, processes, or control technologies for Hg that have been implemented in this source category since promulgation of the current MATS rule . . . Based on the effectiveness and proven reliability of these Hg control technologies, and the relatively short period of time (~six years) since the promulgation of the MATS rule, no developments in practices, processes, or control technologies nor any new technologies or practices were identified."). The commenters stated, further, the 2018 Technology Review memo analyzed subbituminous and lignite coals in separate categories and recognized that while halogen (chlorine) capture was commonly used and appropriate for subbituminous coals, it was sparsely used for lignite coals. *Id*. at 9-10. Commenters asserted that the EPA has failed to provide a reasoned justification why the prior conclusions in the 2018 Technology Review memo should now be abandoned.

Response 8: We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category." The EPA also notes that numerous reference were made to a report developed by Andover Technology Partners (https://www.andovertechnology.com/wp-content/uploads/2021/08/PM-and-Hg-Controls_CAELP_20210819.pdf) in the preamble and in the 2023 Technical Memo (Docket ID No. EPA-HQ-OAR-2018-0794-5789). That report, which was available in the rulemaking docket and was cited by other commenters, is titled "Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants" and contains much detail on advancements in Hg controls and other developments that would allow lignite-fired EGUs to meet a more stringent Hg emission limit. As discussed in section II.D of the final rule preamble, the 2020 Technology Review did not evaluate the current performance of emission reduction control equipment and strategies at existing lignite-fired EGUs. Nor did the 2020 Technology Review specifically address the discrepancy between Hg emitted from lignite-fired EGUs and non-lignite coal-fired EGUs or consider the improved performance of injected sorbents or chemical additives, or the development of SO_3-tolerant sorbents.

Comment 9: Commenters stated that the EPA improperly makes assumptions to reach its conclusion that the new Hg emissions limits are achievable. One final major assumption the EPA makes is that of feasibility. Commenters stated that none of the 22 lignite EGUs are currently in compliance with the proposed new Hg emissions limit. According to EIA's collected data on fuel use in 2021, there are 22 EGUs that were designed to burn lignite. 13 of the 22 EGUs were designed and used refined coal. EPA makes multiple assumptions: that these 13 EGUs used refined lignite, that the EGUs will continue to use refined lignite despite the stated intention to discontinue using refined coal after the tax credits end in 2021, that brominated ACI will yield the same predicted 90% control with refined lignite as with virgin lignite, and that the capture methods currently used can reasonably be transitioned to using brominated ACI. Again, the EPA states that while the Agency is "not proposing to mandate the use of any particular control technology" for lignite coal, it essentially admits that brominated ACI is the only feasible option for lignite coal EGUs (88 FR 24882). The commenter said, further, in concluding that brominated ACI is cost effective, the EPA admits it is using a Gulf Coast lignite EGU as its model and makes no attempt to determine whether the Gulf Coast lignite EGU is representative of other regional lignite-fired EGUs, such as North Dakota Fort Union EGUs that burn lignite coals with significantly different Hg and chlorine concentrations (2023 Technology review memo at 24-25).

Response 9: See section V.C of the preamble for the final rule. There the EPA notes that Twin Oaks units 1 & 2 – both firing Gulf Coast lignite (which has a higher Hg content than lignite mined in North Dakota) has routinely demonstrated the ability to meet an emission limit of 1.2 lb/TBtu. The EPA also notes that, similar to many comments that were received on the 2023 Proposal suggesting that the proposed standard is unachievable, several commenters on the original MATS proposal argued, at that time, that the final Hg limit of 4.0 lb/TBtu for low rank (lignite) coal EGUs was "based on too little data" and was "technically and economically unattainable." (*See* 77 FR 9393).

The EPA assumed use of Gulf Coast lignite in the model plant calculation because the mean Hg content is higher than that of Fort Union lignite and thus should be more challenging to control. The EPA also does not "admit that brominated ACI is the only feasible option for lignite coal EGUs" and the Agency discusses the use of other technologies such as injection of chemical additives. However, even if use of brominated ACI was the only feasible option for lignite coal EGUs, that would not be a reason to not finalize the more stringent Hg emission standard. There is no requirement that the EPA identify more than one control technology to meet a final promulgated emission standard. The EPA does not mandate the use of any particular control technology. Rather, the EPA promulgates numerical emission standards (or, at times, work practice standards) and affected sources may meet the standard using a variety of control technologies or strategies.

Comment 10: Commenters stated that the EPA also overlooked key factors associated with lignite fuel. In asserting that the proposed 1.2 lb/TBtu limit could be achieved with additional activated carbon injection, they argued that the Agency failed to account for the impacts of the higher sulfur content of lignite coal as compared to subbituminous coal, and that such higher sulfur content leads to additional SO_3, which is known to negatively impact the effectiveness of activated carbon.

Response 10: The impact of coal sulfur content and SO_3 is discussed in section V.D of the preamble.

Comment 11: Commenters stated that neither the 2023 Technology Review memo nor the 2023 Proposal provide specific factual evidence to refute the 2020 Final Action or the 2018 Technology Review memo findings that there are no new developments in practice, processes, or control technologies for reduction of Hg emissions in coal-fired power plants. They said without providing the specific evidence that was allegedly considered, the EPA "determined that available controls and methods of operation will allow lignite-fired EGUs to meet the same Hg emission standard that is being met by EGUs firing on non-lignite coals, and the costs of doing so are reasonable." (88 FR 24880). Commenters argued that without that evidence and data, the EPA's alleged "determination" is arbitrary and capricious.

Response 11: The EPA did not rely exclusively (or even mostly) on information obtained from the CAA section 114 information request. The EPA relied on a variety of data sources in developing the proposed Hg emission standards for EGUs burning lignite. This included historical coal analyses, results from demonstration tests (including those conducted by DOE and others), publicly available Hg emissions data, and data and information obtained from owners/operators of lignite-fired EGUs from EPA's limited CAA section 114 information survey. We have discussed the rationale for the final emission standards – including the data and data sources – in section V.D of the preamble and in the 2024 Technical Memo entitled “2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category.”

Comment 12: Commenters stated that CAA section 7412(d)(3)(A) requires the EPA to exclude from its minimum "achievability" analysis for existing sources those that "within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate applicable to the source category and prevailing at the time[.]" The commenters said, however, the EPA has not excluded any sources from its technical analysis of achievable rates on this basis and this results in a skewed analysis towards a lower "achievable" emissions standard using a method explicitly prohibited by the CAA. (5 U.S.C. 706(2): reviewing court shall hold unlawful and set aside agency actions that are "not in accordance with law" and "in excess of statutory [] limitations"); *Bethesda Health, Inc. v. Azar*, 389 F. Supp. 3d 32, 41 (D.D.C. 2019): setting aside as arbitrary and capricious agency action that contradicts its own regulations). Commenters stated that although this requirement is only expressly listed with respect to setting the initial MACT floor, it would be unreasonable and arbitrary to interpret requirements imposed under technology review not to be subject to the same requirement since the EPA could otherwise easily circumvent the statutory limit at will simply by adding such sources back to its achievability analysis under each successive technology review period. They said that in any case the EPA has not identified any rationale for exempting CAA section 112(d)(6) technology review determinations from this same constraint. The commenters stated that in accordance with the CAA, the EPA must determine what the LAER rate is for this category, and then exclude from its achievability analysis any sources that already meet the lower emissions limit contemplated in the 2023 Proposal.

Response 12: As the commenters noted the CAA section 112(d)(3)(A) requirement is only expressly listed with respect to setting the initial MACT floor. However, the EPA does not interpret this as required under the CAA section 112(d)(6) technology review and it has not been the Agency’s prior practice.

4.4 Proposed Revision of the Hg Emission Standard for Lignite-Fired EGUs

4.4.1 Both Lignite and Subbituminous Coal Are Low Rank Coals With Low Halogen Content

Comment 1: Commenters stated that the 2023 Proposal assumes sorbent injection Hg removal observed with PRB (subbituminous) coals is achievable for lignite. They said that the EPA finds that increasing sorbent injection rate and adding halogens (to compensate for loss of refined coal) will be equivalently effective. The commenters argued that this assumption is incorrect.

Commenters stated that NRECA’s Technical Analysis confirms that North Dakota lignite coals have a distinctly different composition as compared to PRB. The commenters said that one particularly relevant difference is sulfur content and said lignite flue gas causes measurable SO_3 in quantities that - as summarized by the EPA’s contractor for IPM model inputs - reduce the effectiveness of sorbent by 50% and in some cases present a barrier to 90% Hg removal. They said that the EPA's analysis must take this fact into consideration.

Commenters stated that in relying heavily on the performance of a single power plant that uses halogenated activated carbon injection to control Hg, the EPA's reasoning in the proposal amounts to the following:

> "For the 2012 MATS Final Rule, the EPA calculated beyond-the-floor costs for Hg controls by assuming injection of brominated activated carbon at a rate of 3.0 lb/MMacf for units with ESPs and injection rates of 2.0 lb/MMacf for units with baghouses (also known as FF). Yet, in responses to the CAA section 114 information survey, only one facility (Oak Grove) explicitly indicated use of brominated activated carbon. Oak Grove units #1 and #2 (both using FF for PM control) reported use of brominated activated carbon at an average injection rate of less than 0.5 lb/MMacf for operation at capacity factor greater than 70%. The Oak Grove units fired, in 2021, using mostly refined coal. That injection rate is considerably less than the 2.0 lb/MMacf assumed." (88 FR 24881)

Commenters stated that Oak Grove is not the only lignite-fired facility that utilizes halogenated activated carbon – Coyote uses it too, but the EPA did not examine data from Coyote. Commenters stated that Oak Grove is also not representative of most, if not all other, lignite-fired facilities. Oak Grove is a relatively new facility that began operation in 2009/2010 and is the only 100% lignite-fired EGU that utilizes SCR reduction for NO_x control. They said, as the EPA correctly acknowledges, while a SCR system that has been installed for NO_x control does not itself capture Hg, it can under the right conditions enhance the oxidation of Hg^0 in the flue gas. Commenters stated that SCR is not a demonstrated technology for North Dakota Lignite EGUs (and certainly not cost-effective for Hg control even if the EPA disagrees about the feasibility of SCR for lignite). They said, in addition, as the EPA acknowledges, Oak Grove applied an aqueous bromine salt to the coal in addition to the use of brominated activated carbon. The commenters asserted that there was no attempt by the EPA to evaluate the impact of this "coal refinement" technique nor does the EPA make any attempt to compare the Hg control effectiveness of the halogenated activated carbon at Oak Grove to that of PRB subbituminous coal-fired EGUs. They said putting aside the SCR and use of refined coal at Oak Grove, the average Hg emission rates of the two units at that plant at an ACI rate of about 0.5 lb/MMacf, according to the EPA, was 2.01 to 2.59 lb/TBtu. The commenter said that the average Hg emission rate for the Big Stone Plant, also equipped with an SCR and at a halogenated ACI rate of about 0.4 lb/MMacf (and even without using refined coal), was 0.5 lb/TBtu. They said, that is, the empirical data show PRB coal is so different from lignite that roughly the same ACI rates resulted in Hg emission rates at the lignite-fired Oak Grove EGUs four to five times larger than the Hg emission rates at the PRB subbituminous coal-fired Big Stone Plant. They concluded, clearly, controlling Hg from subbituminous coal-fired EGUs and lignite-fired EGUs is not the same.

Commenters stated that to highlight the real-world difference between the ability of lignite-fired and PRB-fired EGUs to control Hg, they created a table to show a comparison between their similarly configured Big Stone Plant and Coyote Station facilities. Additionally, they included figures showing rolling 30-boiler operating day average Hg emission rates and the daily average

ACI feed rates for Big Stone Plant and Coyote Station for years 2021-2022. Their table showed that Big Stone Plant (which is PRB-fired) and Coyote Station (which is North Dakota lignite-fired) are similarly configured plants that utilize the same halogenated ACI for Hg control. The commenters said, however, Coyote Station's average sorbent feed rate on a lb/MMacf basis is more than three times higher than Big Stone's, yet Coyote Station's average Hg emissions on a lb/TBtu basis are more than five times higher than Big Stone's.

Commenters stated that as a result of treating EGUs burning subbituminous coal as burning lignite coal, seven EGUs were considered "lignite-fired EGUs" in the EPA's analysis even though they use 0% lignite coal. They said this also includes at least one EGU that co-fires natural gas, which influences the Hg lb/TBtu values submitted.

Commenters also noted that a 90% Hg removal is required to meet 1.2 lb/TBtu for North Dakota lignite and this value exceeds the nominal 80% removal estimated by the EPA. They said that greater than 90% value is unlikely to be sustained over a longer period of time such as a 30-day rolling average basis. The commenters argued that the EPA must step away from equating PRB coal and lignite coal as these coals are not equivalent for Hg control purposes.

Response 1: The EPA has not equated PRB (subbituminous) coal and lignite and has not suggested that the coals are equivalent or that they are not distinct ranks of coal. However, the EPA has noted that subbituminous coal and lignite (both Fort Union and Gulf lignites) are MUCH more similar than subbituminous coal and bituminous coal. Yes, despite subbituminous and bituminous coals being quite different – with respect to their alkalinity, their Hg content, their halogen content, their heating value, their sulfur content, their moisture content, etc. … they are still subjected to the same Hg emission limit – 1.2 lb/TBtu. All types of coal – eastern and western bituminous coal, western subbituminous coal, anthracite, waste coal, coal refuse, etc. – all are quite different in many, many ways. But they are all subject to the same emission limit – 1.2 lb/TBtu. The fact that lignite has some characteristics that are unique is the reason that it is a separate class/rank of coal. However, as the EPA has discussed in the 2023 Proposal, in the 2023 and 2024 Tech Memos, and in the preamble for the final rule, many of the properties of lignite that challenge the control of Hg are shared by other coal types that are able to meet the 1.2 lb/TBtu emission limit.

Comment 2: Commenters stated that both lignite and PRB coal do contain less chlorine than bituminous coal, but other major differences in composition exist that the EPA does not recognize, such as the sulfur content and the alkalinity of inorganic matter. Commenters stated that the EPA's failure to recognize these differences manifests itself as assuming ACI effectiveness observed on subbituminous coal (specifically PRB) extends to lignite. Commenters included a figure showing the variability of sulfur content for eight North Dakota lignite mines as well as a figure showing the variability of fuel alkalinity compared to sulfur content for eight North Dakota mines – specifically, the ratio of calcium and sodium to sulfur – *i.e.,* the (calcium + sodium)/sulfur metric.

Response 2: The differences (and similarities) in composition and other properties of lignite and subbituminous coal (and other coals) are discussed the section V of the final preamble and in a supporting technical memorandum titled "1998 ICR Coal Data Analysis Summary of Findings."

All coal types have variable properties. All coal types have variable Hg content. Bituminous coals, in particular, have a wide range of properties as they are mined in a variety of regions in the U.S. This includes bituminous coal from the upper Appalachian region, the mid- and lower Appalachian regions, the interior states (*e.g.*, IL, IN, OH, *etc.*). The U.S. has also imported lower sulfur bituminous coals from Columbia. Because of their typically higher sulfur content, many bituminous coals produce relatively higher levels of SO_3 in the flue gas (… which can be enhanced further for sources with an installed SCR for NO_x control). Yet, all of these coals – with a very wide range of compositions and properties – are all subject to the 1.2 lb/TBtu Hg emission standard.

Comment 3: Commenters stated that the EPA acknowledges that "the halogen content of the coal — especially chlorine — largely influences the oxidation state of Hg in the flue gas stream" (2023 Technology Review memo at 22), but then goes on to state that lignite and PRB coals should have similar Hg capture rates despite citing to the U.S. Geological Survey publication entitled "Mercury and Halogens in Coal—Their Role in Determining Mercury Emissions From Coal Combustion." The U.S. Geological Survey publication fails to distinguish between the chlorine contents of lignite and PRB coals (See USGS Publication at Figure 5), but acknowledges that PRB coals can have lower Hg concentrations than lignite coals and that Hg concentration depend on the geographic area from which the lignite and PRB coals are obtained.

Response 3: Both subbituminous coal and lignite have relatively lower natural halogen (and higher natural alkalinity) and need to add additional halogen to oxidize the Hg^0 vapor in the flue gas stream for effective capture.

4.4.2 The Hg Content of Fort Union Lignite and PRB Subbituminous Coal Are Similar

Comment 1: Commenters stated that the EPA's proposal to lower the Hg standard for lignite-fired EGUs ignores the complete chemical composition of lignite-coal and technical challenges in Hg control technologies for EGUs firing lignite coal. They argued that the Agency ignores the wide variability of Hg content, sulfur content, and alkalinity of inorganic matter in Fort Union (North Dakota) Lignite. The commenters stated that the EPA assumes an average Hg content for Fort Union lignite of up to 7.8 lb/TBtu and that assumption is not supported by any test data – EPA's analysis relies solely on the IPM assigned inlet Hg content value of 7.81 to derive an 85% Hg control rate to meet a 1.2 lb/TBtu standard.

Commenters stated that the average 2021 inlet Hg concentrations for the Oak Grove units were greater than 25 lb/TBtu, compared to the average inlet concentration of 5.5 lb/TBtu that the EPA assumes for subbituminous coal. They said that to achieve a 1.2 lb/TBtu Hg limit with an inlet concentration of 5.5 lb/TBtu, a source must achieve an approximately 78% control efficiency, whereas to meet that limit with a 25 lb/TBtu inlet concentration, a source must achieve a greater than 95% control efficiency. Commenters stated that the EPA must account for the stark difference in the inlet Hg concentrations as it assesses whether the same limit is appropriate for the different fuels. The EPA instead decides to focus on annual average Hg emission rates from lignite-fired EGUs in 2021. Commenters stated that a unit's annual average emission rate does not account for the fluctuations in stack emissions that occur when looking at a 30-day rolling average—the averaging period for the standard here—and it also ignores the reductions and control efficiencies already achieved given the initial Hg content of the fuel.

Commenters stated that the EPA asserts in the preamble that "The Hg Content of [North Dakota] Fort Union Lignite and PRB Subbituminous Coal Are Similar." (88 FR 24881). They said that in support of this proposition, the EPA states:

> "As can be seen in Table 8 above, for the 2012 MATS Final Rule, the EPA estimated the Fort Union lignite-fired EGUs inlet Hg concentration at up to 7.8 lb/TBtu and estimated the inlet Hg concentration of subbituminous coal-fired EGUs at up to 8.65 lb/TBtu. These values are very similar to results from a published study that found the average Hg concentration of Fort Union lignite and PRB subbituminous coals to be very similar. The study found that the Fort Union lignite samples contained an average of 8.5 lb/TBtu and the PRB subbituminous coal samples contained an average of 7.5 lb/TBtu." (88 FR 24881)

Commenters stated that there is no information on PRB subbituminous coal Hg content in Table 8 of the preamble. Commenters suspected that the EPA instead meant to reference Table 7-6 of Chapter 7 of the IPM Documentation, which lists ranges of Hg content for various types of coal in the U.S. In particular, Table 7-6 does include an average Hg content of 8.65 lb/TBtu for "Medium Sulfur Subbituminous (SE)." They said, however, tracing back the designation of "Medium Sulfur Subbituminous (SE)" to Tables 7-4 and 7-1 of the IPM Documentation, the coal supply for that designation is not PRB coal at all; it is a coal from San Juan, New Mexico.

Commenters stated that in contrast, Wyoming PRB subbituminous coal, according to Table 7-6, has a substantially lower Hg content of 2.03 to 6.44 lb/TBtu. They said that compared to the North Dakota lignite data in the IPM documentation, the EPA's own data suggests that Wyoming PRB subbituminous coal has an inlet Hg concentration less than half of North Dakota lignite, again highlighting the difference in Hg content between the two types of coal.

Commenters included a figure illustrating how actual chemical composition tests for lignite from Fort Union mines in North Dakota show a substantial Hg content variability within each mine. Commenters stated that the data reported in the figure also show how high the Hg content of North Dakota lignite typically is: the 75th percentile of data from each lignite supplier significantly exceeds EPA's value of 7.8 lb/TBtu by a substantial margin. They said that for one North Dakota lignite mine, the 75th percentile Hg content is upwards of 18 lb/TBtu, more than double the EPA's assumption and based on these actual Hg content data for North Dakota lignite mines, achieving a 1.2 lb/TBtu requires an Hg removal rate of approximately 93-95% for unavoidable instances where lignite Hg content is at the 95th percentile of observed values. The commenters said that such high removal efficiencies cannot be achieved by sorbent injection and argued that they certainly cannot be achieved given the other chemical composition differences between lignite and PRB coals.

Commenters presented drill core data and indicated that there are many examples where two or three Hg samples were analyzed from the same core. They provided some examples of the variability in a table presented by the commenters where samples with the same drillhole ID are from different seams of the same boring. They said that these samples were taken just feet apart from one another, which means it will be mined and hauled to the plant immediately for fuel. The commenters said that given the variability of the different seams, it's apparent that periods when inlet Hg is much higher than the 7.76 lb/TBtu the EPA claims in its calculations will occur and should the plant receive a slug of 32 lb/TBtu coal, that would require greater than 96% removal to maintain a limit or 1.2 lb/TBtu. Commenters stated that the EPA should acknowledge the wide variability in lignite coal and retain the lignite subcategory.

Commenters presented a figure showing Hg content and variability for eight North Dakota lignite mines compared to the fixed value of 7.7–7.8 lb/TBtu, assumed by the EPA as representing North Dakota lignite, as summarized in Table 11 of the 2023 Technology Review memo. The figure shows – with the exception of the Tavis seam – all mean values of Hg content exceed the EPA's assumed value that serves as the basis of the EPA's evaluation. The commenters said more notably, the 75th percentile value of Hg for each seam – slightly more than one standard deviation variance from the mean – in all cases significantly exceeds the value assumed by the EPA. Commenters stated that of note is that the variability of Hg depicted in their figure is not necessarily observed only over extended periods of time – such as months or quarters – it can be witnessed over period of days or weeks. This is attributable to the sharp contrast in Hg content of seams that are geographically proximate and thus are mined within an abbreviated time period. Commenters provide a table showing that achieving a 1.2 lb/TBtu requires an Hg removal rate of approximately 93-95% for unavoidable instances where coal Hg content is at the 95th percentile of observed value. They said that the approximate 93-95% Hg removal requirements well exceed the 85% Hg removal based on the IPM-assigned Hg content.

Commenters presented a physical map showing the location of "boreholes" in a lignite field with imbedded text describing the Hg content as ppm. They said that these example boreholes–separated by typically 660 feet–and the factor of 3 to 6 variation of Hg content present a meaningful visualization of Hg variability in a lignite mine, and the consequences for the delivered fuel.

Response 1: For this final rule, the EPA re-evaluated coal data from the 1998 ICR data (as explained in great detail in the preamble and in a supporting technical memorandum titled "1998 ICR Coal Data Analysis Summary of Findings" available in the rulemaking docket. Specifically, the EPA evaluated the coal Hg data to characterize the Hg content of lignite mined in North Dakota, Texas, and Mississippi and to characterize by seam and by coal delivered to a specific plant. The results are presented as a range of Hg content of the lignites as well as the mean and median Hg content. The EPA also compared the fuel characteristics of lignites mined in North Dakota, Texas, and Mississippi against coals mined in Wyoming (subbituminous coal), Pennsylvania (mostly upper Appalachian bituminous coal), and Kentucky (mostly lower Appalachian bituminous coal). The Agency also included in the re-evaluation, coal analyses that were submitted in public comments by North American Coal (NA Coal). In addition to the Hg content, the analysis included the heating value and the sulfur, chlorine, and ash content for each coal that is characterized.

Comment 2: Commenters stated that the 2023 Proposal will create drastic consequences for as reducing the lignite emissions standards to levels of other coal ranks effectively eliminates the lignite sub-category. They said that the EPA has well documented support from the original rule for lignite as a subcategory. Commenters encouraged the EPA to review the original documentation and, at a minimum, reaffirm the lignite category at the emissions standards as they currently exist. They said that the EPA does not have the scientific justification to support the 2023 Proposal's emission standards. They said further that in some cases, the EPA decided to rely on information from nearly 30 years ago versus collecting new information or even using the information obtained during the original rule development: "EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGU s that EPA obtained pursuant to an ICR under the authority of section 114 of the CAA. 65 FR 79826-27". 76 FR 24976, 24984.4 42 U.S.C. section 7412(d)(6).

Commenters stated that the EPA presented a body of evidence in the original 2011 Proposal and 2012 MATS Final Rule in support of the lignite category, for example:

> "For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12% of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP." 76 FR 25037.

Commenters said that they agree with the EPA's assessment in the 2012 MATS Final Rule and that none of this information has changed. They said however, the EPA now claims to have determined, from a 1994 published study, that the 20 Hg content of North Dakota lignite and PRB subbituminous coal are similar and uses this as rationale to refute the credible information utilized in the 2012 MATS Final Rule. Commenters reviewed the 1994 published study and believe the EPA is egregiously misrepresenting (or ignoring) the conclusions reached in the study. They said the 1994 published study states that these results demonstrate the importance of using up-to-date information when assessing emissions at electric utilities or 21 other sources. Since the EPA relied on this 1994 paper to conclude that North Dakota lignite is comparable to PRB subbituminous coal, the Agency should heed the advice of the authors and use up-to-date information instead of a study from nearly 30 years ago. The commenters stated, further, this 1994 data was also available at the time of the 2011 Proposal but did not sway the final EPA decision that lignite was, in fact, "different". The commenters said that based on the lack of new scientific data, this appears to show that the EPA is seeking out and selectively choosing data to support its prepackaged conclusion to lower the lignite Hg standard. They argued that if the EPA was interested in better understanding the Hg concentrations and how much they vary per coal seam and per coal mine, it would have worked with commenters and the North Dakota lignite EGU industry to obtain this information.

Commenters noted that as stated throughout the 2011 Proposal and 2012 MATS Final Rule, the EPA recognized the importance of up-to-date data in determining Hg emissions limits, which is why much of the 2010 ICR data confirmed the subcategorization for Hg (and not the other pollutants). Commenters requested that the EPA explain its decision to now revert to an older 1994 published study to "change" the determination from the 2010 ICR data.

Response 2: For this final rule, the EPA re-evaluated coal data from the 1998 ICR data (as explained in great detail in the preamble and in a supporting technical memorandum titled "1998 ICR Coal Data Analysis Summary of Findings" available in the rulemaking docket. The EPA has updated its assumptions regarding Hg content (and variability) based on that evaluation.

4.4.3 The Hg Content of Gulf Coast Lignite Is Greater Than That of Fort Union Lignite; and Several Lignite-Fired EGUs in Texas Have Co-Fired Significant Quantities of Subbituminous Coal

Comment 1: Commenters stated that the EPA's proposal to lower the Hg standard for lignite-fired EGUs ignores the complete chemical composition of lignite-coal and technical challenges in Hg control technologies for EGUs firing lignite coal. They said the EPA ignores the wide variability of Hg content, sulfur content, and alkalinity of inorganic matter in Gulf Coast Lignite. Commenters stated that the Hg content of Gulf Coast lignite coal is high: the 75th percentile from Mississippi and Texas mines exceeds 40 lb/TBtu and 29 lb/TBtu, respectively. Commenters included a figure depicting the Hg content variability for Mississippi and Texas.

Commenters stated that the EPA in the 2023 Proposal assigned an Hg inlet value of 12.44 to 14.88 lb/TBtu to Gulf Coast lignite, deriving a control rate ranging from 80% to 90% to meet the 1.2 lb/TBtu standard. The commenters said that however, based on actual Hg content data for Gulf Coast lignite, achieving a 1.2 lb/TBtu requires an Hg removal rate of approximately 96% - 97% for unavoidable instances where lignite Hg content is at the 95th percentile of observed values. They said that current Hg control technologies available for lignite-fired EGUs cannot reach these theoretical control efficiencies and that this is exacerbated by other chemical composition differences between lignite and PRB coals.

Commenters stated that the differences between North Dakota and Texas lignite coal do not support the EPA's assumption that all Hg emission reduction technologies apply equally to all lignite. They said the EPA relies on Texas' Oak Grove EGU's use of the brominated ACI and use of refined lignite to justify the Agency's reasoning that use of brominated ACI would be effective to reduce Hg emissions for all lignite coal. Commenters stated that this facility uses SCR, which is not a compatible technology with North Dakota lignite. Commenters stated that the EPA failed to even explore whether SCR (via the introduction of halogens) is technically feasible for North Dakota lignite coal. They said, in actuality, the EPA has recognized that SCR is likely infeasible for North Dakota lignite to reduce Hg concentrations as required in the 2023 Proposal.

Commenters stated that in the past, the EPA has worked with a consultant that recognized, "[w]ith flue gas SO_3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater Hg removal may not be feasible in some cases." Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Project 12847-002, at 3 (Mar. 2013). They said that this is because North Dakota lignite has significantly higher sodium content than PRB coals and the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 µm. The commenters said that as a vapor or as a very small particle, sodium will pass through any upstream emissions control equipment and will reach the SCR regardless of whether the SCR is located before other emission control devices (high-dust configuration) or after those other controls (low-dust or tail-end configurations). They went on to say that once the sodium particles reach the SCR, they plug the pores of the catalyst, which are the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive. The commenters said that recent efforts to address these concerns through either cleaning or regeneration of the catalyst have not been successful, even at pilot scale. They said that a study recently cited by the North Dakota Department of Environment Quality provides additional details on these efforts and the unsolved technical challenges that remain regarding the impact of alkali metals in North Dakota lignite on the technical feasibility of SCR.

Commenters stated that this is not new information to the EPA and the EPA previously challenged North Dakota's determination that SCR was not a demonstrated BACT in lignite-fired EGUs in United States v. Minnkota Power Coop., Inc. They said that in Minnkota, a US District Court agreed with North Dakota's determination that SCR was not justified or feasible as a BACT for lignite-fired EGUs. The commenters said, importantly, the EPA did not appeal or challenge this ruling.

Commenters stated that for these reasons, the EPA's attribution of the lower Hg emissions to the substantial amounts of PRB coal used in Texas lignite-fired EGUs is not appropriate for extrapolation to North Dakota lignite-fired EGUs. They said according to EIA 2021 data provided in Table 7 of the 2023 Proposal, 13 of the 21 facilities are listed as using significant portions of refined coal (often greater that 90%), while the EPA simultaneously admits it does not have data on the type of coal that is refined. They said, further, only five of the listed facilities burn lignite in concentrations over 30%. Commenters stated that without a clearer picture of the makeup of that refined coal, and how it differs from lignite plant burning non-refined coals, the EPA's conclusions are not reasonably justified.

Response 1: For this final rule, the EPA re-evaluated coal data from the 1998 ICR data (as explained in great detail in the preamble and in a supporting technical memorandum titled "1998 ICR Coal Data Analysis Summary of Findings" available in the rulemaking docket. The EPA has updated its assumptions regarding Hg content (and variability) based on that evaluation. The impact of coal sulfur content and SO_3 is discussed in section V.D of the preamble. Contrary to commenters assertions, the EPA has not proposed or suggested that SCR is a required component of Hg control for EGUs firing North Dakota lignite.

4.4.4 The Proposed More Stringent Hg Emission Standard Can Be Achieved, Cost-Effectively, Using Available Control Technology

Comment 1: Commenters stated that Hg emissions limits of 0.15 lb/TBtu for not-low-rank coal units and 0.5 lb/TBtu for low-rank coal units would be achievable for units with a range of control configurations. They said that for units with an ESP but no scrubber, which are particularly challenging to control for Hg, ACI can be used, and the rate of injection increased to improve the rate of Hg removal. The commenters said that to the extent that some units with an ESP may be required to install a baghouse to comply with a more stringent fPM standard, the baghouse by itself is likely to improve the Hg emissions rate without an increase in injection rate.

Commenters stated that the 2023 Proposal's contention that the anticipated enhanced use of brominated activated carbon at lignite plants as a result of this rule could have "positive non-air impacts" seems reasonable. The summary of Hg control technologies used at each lignite plant shows that most use a combination of halogen-based Hg control techniques, including brominated activated carbon; precombustion treatment of coal with bromine; and spraying bromine into the combustion chamber. The commenters said that as the 2023 Proposal emphasizes, the amount of bromine associated with brominated activated carbon use is much less than the amount used with these other technologies. They said moreover, unlike these other technologies which can release halogens to air and water at various points, the bromine remains bound to the particles where it reacts to capture gaseous Hg and then, in turn, is captured by downstream pollution control devices (*e.g.,* an FF). Commenters agreed that any cross-media transfers of bromine to receiving water bodies and emitted to the atmosphere with the use of brominated activated carbon "are not expected (or would certainly be lower) with the use of brominated solvents" relative to these other technologies.

Commenters stated that there is likely to be some cost associated with achieving a 0.5 lb/TBtu Hg standard for low-rank coal units, as none of the 20 low-rank coal units that do not have announced retirement dates by 2027 have achieved a Hg emissions rate at or below that level, but all of them have a baghouse or a scrubber installed which suggests they are capable of achieving very low emissions. They said that the use of a baghouse or scrubber means very high capture efficiencies are expected to be achievable, as ACI or chemical additives should be effective for lowering Hg emissions rates. The commenters said that ACI has been very effective in reducing Hg emissions to well below 0.5 lb/TBtu in not-low-rank coal units, which suggests this rate should be achievable for low-rank coal units.

Commenters stated that for not-low-rank coal units, 35 of the units that have not announced plans to retire by the end of 2027 had Hg emissions under 0.15 lb/TBtu with a variety of PM control devices. These include units with an ESP, a baghouse, both an ESP and a baghouse, or a venturi scrubber, which shows that this level of Hg emissions is achievable for a range of control configurations. Units with a scrubber, baghouse, or REACT technology (using activated coke to capture NO_x, SO_2, and Hg) may be capable of achieving this rate without ACI, and in some cases these units may use fuel additives or scrubber chemical additives instead of ACI to achieve lower Hg emissions rates. The commenters said that four of the units that have achieved Hg emissions below 0.15 lb/TBtu have only an ESP but no scrubber for acid gas control and therefore, available information regarding these units shows that a Hg emissions rate of 0.15 lb/TBtu is feasible for not-low-rank coal units and demonstrated for a range of control configurations.

Commenters stated that though the EPA has access to information regarding types of sorbents used by units in the Air Market Program Data, the type of sorbent and rate of injection are not required to determine whether additional Hg reductions are feasible and cost-effective at coal units. ATP has previously estimated incremental costs of controls to lower Hg emission rates for low-rank and not-low-rank units, and for not-low-rank units there is significantly more data available to the EPA that can be used to evaluate costs of compliance with a lower Hg standard than was available when MATS was promulgated. The commenters said that the Agency has years of Hg emissions data, information regarding coal type, air pollution control configuration, and the type of carbon being used. The commenters said that published material on ACI and other approaches, as well as publicly available data relevant to control costs at different rates and for different configurations, provides adequate information to determine additional reductions that are achievable at reasonable costs.

Response 1: The EPA acknowledges these supportive comments. However, the EPA has not proposed any revisions to Hg emission standard for EGUs firing coal other than lignite. Nor, has the EPA proposed revision to the Hg emission standard for lignite-fired EGUs below the value of 1.2 lb/TBtu that is being finalized in this action. CAA section 112(d)(6) requires that the EPA review and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards at least every 8 years. The EPA will continue to evaluate developments in practices, process, and control technologies and will propose revised emission standards, if warranted.

Comment 2: Commenters stated that they identified two significant mathematical errors that the EPA must correct. They said the EPA's cost effectiveness calculation is based on a model plant analysis for a hypothetical 800 MW lignite unit and the EPA assumes that the hypothetical plant would meet the current standard of 4.0 lb/TBtu by injecting 2.5 pounds of non-brominated activated carbon per million actual cubic feet (106 acf), and the EPA assumes that 5.0 lb/106 acf of brominated activated carbon would be needed to meet the proposed standard of 1.2 lb/TBtu. The commenters said that then, the EPA calculates the hourly amount of carbon required under each of these two scenarios using the following equation:
2.5 lb sorbent/MMacf × 9860 scf/MMBtu × 520 R/785 R × 8,880 MMBtu/hr × 1 MMacf/1,000,000 acf = 287 lb sorbent/hr

Commenters stated that this equation contains two critical errors. First, the term intended to convert standard temperature to actual temperature is inverted. The correct conversion factor is 785 R / 520 R. Second, the F-factor of 9,860 scf/106 Btu provides the volume of flue gas produced from combusting one million Btu of lignite at stochiometric conditions (*i.e.,* 0% excess air), whereas typical flue gas contains approximately 50% excess air and would be 6% O2 wet, so the 9,860 factor must be increased by (20.9 ÷ (20.9 – 6.0)). The commenters said that these errors are corrected in the revised equation below to provide a more a realistic volumetric flow rate for a hypothetical 800 MW lignite unit:

9860 scf/MMBtu × 20.9/(20.9 - 6) × 785 R/520 R × 8,880 MMBtu/hr = 1.83 × 106 acf/hr

Commenters stated that using this equation, more realistic hourly injection rates can be computed. At 2.5 lb/106 acf, the hourly injection rate would be 457 lb/hr, well above the EPA's estimate of 114 lb/hr. And, at 5.0 lb/106 acf, the hourly injection rate would be 915 lb/hr, well above the EPA's estimate of 287 lb/hr. The commenters stated that when the other assumptions that the EPA used to estimate annual cost effectiveness are applied, the resulting cost effectiveness value reveals the significance of these two errors. They said further that based on the EPA's assumptions for capacity factor (80%) and cost per pound of sorbent ($0.80 non-brominated; $1.15 brominated), the annual cost for 2.5 lb/106 acf of non-brominated injection would be $2,560,000 per year, and the annual cost of 5.0 lb/106 acf brominated injection would be $7,370,000 per year, for a difference of $4,810,000 per year. The commenters said since the hypothetical plant would also emit 247 lb per year and 47 lb per year in the two scenarios, respectively, the correct cost effectiveness value can be calculated as follows:

Incremental cost effectiveness = {($7.37 × 106 - $2.56 × 106)/(247 - 74)} = $27,800 per lb Hg

Commenters stated that these errors together result in an underestimate of the annual cost effectiveness value by more than a factor of three. They said that the EPA calculates a cost effectiveness of $8,703 per pound of Hg removed, but the corrected formula yields a cost of $27,800 per pound. The commenters said that this cost difference is significant and impactful enough to have caused a different rulemaking outcome and that the EPA must reconsider whether the proposed Hg limitation would be cost-effective and reasonable.

Commenters stated that the EPA has significantly underestimated costs of reducing emissions to 1.2 lb/TBtu. The commenters said that the NRECA Technical Analysis found that the EPA's calculation of cost–effectiveness for lignite fuels ignores the role of FGD, present in 18 of the 22 reference stations, in removing Hg. They said that study concludes that this erroneous assumption may cause an under-estimation of the cost for additional Hg removal. The commenters said that the errors in the EPA's formula cast further doubt of the cost effectiveness of achieving 1.2 lb/TBtu. The commenters concluded that the EPA must consider the cost burden of compliance as to small entities and asked for this consideration in light of the fPM costs and the cumulative cost impacts of other rulemakings by the Agency.

Response 2: The EPA acknowledges the error in the model plant cost calculation/equation provided in the 2023 Technical Memo (Docket ID No. EPA-HQ-OAR-2018-0794-5789). The EPA has corrected the equation (as shown in the 2024 Technical Memo) and calculated the cost per lb of Hg controlled for a model 800 MW lignite-fired EGU, as described in the 2024 Technical Memo. For an 800 MW EGU firing Texas lignite EGU, the cost effectiveness of using the brominated carbon sorbent at an injection rate of 3.0 lb/MMacf was $3,050 per lb of Hg removed while the incremental cost effectiveness was $10,895 per incremental lb of Hg removed. The cost effectiveness of using the brominated carbon sorbent at an injection rate of 5.0 lb/MMacf was $5,083 per lb of Hg removed while the incremental cost effectiveness was $28,176 per incremental lb of Hg removed. These costs are below or reasonably consistent with the cost effectiveness that the EPA has found to be acceptable in previous rulemakings for Hg controls.

Comment 3: Commenters stated that the capture of Hg by wet FGD – in many cases prompted by the role of SCR catalysts to oxidize Hg^0 – can be a primary mean for Hg capture. They said however, such co-benefits are highly variable, and depend on the ratio of elemental to oxidized Hg in the flue gas, and the consequential Hg "re-emission" by a wet FGD. They said that there are means to remedy this variability in some instances, but broad success cannot be assured and without the specifics of FGD design and operation, Hg removal via wet FGD cannot be predicted.

Commenters stated that the fate of Hg entering a wet FGD is uncertain. They said if in the oxidized state, Hg upon entering the FGD solution can (a) remain in solution and be discharged with the FGD-cleansing step of "blowdown" (b) precipitate as a solid and be removed with the byproduct (typically gypsum), or (c) be reduced from the oxidized to the elemental state, thus re-emitted in the flue gas. The commenters said that several means to minimize Hg re-emission exist, including injection of sulfite and controlling the scrubber liquor oxidation/reduction potential – these means can limit Hg remission but are additional process steps that are superimposed upon the task of achieving high efficiency SO_2 removal. They said the extent these means can be universally applied without compromising SO_2 removal is uncertain.

Commenters stated that an in-plant study showed that increasing load for a wet FGD-equipped unit can elevate Hg re-emission, eventually exceeding 1.2 lb/TBtu. The commenter said that this observation can be due to loss of the control over the oxidation/reduction potential – a key factor in FGD Hg removal. They said the chemical additives can adjust oxidation/reduction potential but complete and autonomous control may not be available – for example, in a systematic evaluation of FGD operating variables conducted at a commercial power station, factors such as limestone composition and the extent to which units must operate in zero-water discharge – as perhaps mandated by the pending Effluent Limitation Guideline – can affect ORP and thus Hg-reemission.

Commenters stated that upsets in wet FGD process conditions can prompt Hg re-emission – specifically, one observer noted two units that "….experienced a scrubber reemission event causing the Hg stack emissions to increase dramatically above the MATS limit and significantly higher than the incoming Hg in the coal and the event lasting for several days." (Pavlisch, J. et. al., 2016). The commenter said this high Hg event was eventually remedied over the short-term operation, but long-term performance is not available.

Commenters stated that lignite is a high moisture content, low-rank coal and is typically mined adjacent to the powerplant to reduce shipping costs – as a result, the fuel (*i.e.,* lignite) is a key component of the design of the boiler adjacent EGU. The commenters said that lignite-fired EGUs cannot simply switch to a different type of coal, and they stated that attempting to mine around lignite seams with higher Hg concentrations is neither feasible nor consistent with how the EPA applies the NESHAP standards. Commenters argued that given the inherent variability of Hg content within each mine and each mine seam, the fact that the EPA used annual average Hg content data from 2021 to support their control and costs analyses is troubling because the averaging time for the emission limits is a 30-operating day rolling average.

Response 3: The EPA has focused on the use of sorbent injection technologies – either pre-halogenated or in combination with chemical additives. There are many advanced sorbent – including non-carbon sorbent, SO_3 tolerant sorbents, "concrete friendly" sorbents to choose from. Moreover, every lignite-fired EGU is either equipped with a FF/baghouse or a scrubber plus PM control (ESP or FF). So, there are also opportunities to enhance Hg control with the downstream control technologies.

Comment 4: Commenters stated that the EPA focuses on the fact both lignite and PRB coals have low halogen content and produce difficult-to-control Hg^0 vapor in the flue gas stream to conclude that lignite-fired EGUs can simply increase the amount of halogenated sorbent injected to reduce Hg emissions to 1.2 lb/TBtu – a limit that PRB coal-fired EGUs are able to consistently meet. The commenters said that the EPA, however, fails to recognize very consequential differences in the chemical composition of lignite and PRB coals that result in very different Hg removal effectiveness for sorbent injection for the two coals.

Commenters stated that specifically, one of the most important characteristics of PRB coal is that it typically has very low sulfur content, with combustion resulting in very little – "essentially unmeasurable" – SO_3 in the flue gas. They said in contrast, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows much higher levels of SO_3 in lignite-generated flue gas.

Commenters stated that SO_3 in the flue gas has a substantial and well-documented detrimental effect on the Hg removal effectiveness of activated carbon sorbent, the material used to capture Hg emissions. They said Sargent & Lundy, the EPA's contractor in preparing an analysis of Hg control technology, recognized the impact of SO_3 on activated carbon sorbent Hg removal effectiveness, stating "'[w]ith flue gas SO_3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater Hg removal may not be feasible in some cases. The commenters said that based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO_3 increase from just 5 ppmv to 10 ppmv.'"

Commenters stated that additionally, flue gas SO_3 further complicates Hg removal because of operational temperature. The commenters said that lignite-fired EGUs that emit measurable levels of SO_3 observe higher gas temperatures at the air heater exit. They said the air heater exit is also the location activated carbon sorbent is injected to avoid corrosion. The commenters said that pilot plant studies have shown that an increase of gas temperature at the heater exit from 310°F to 340°F decreased sorbent Hg removal by 13% from 81% to 68%.

Commenters stated that lignite and PRB coal are different and said that taken together, these differences – the high variability of Hg content in lignite coal that would require Hg control efficiencies greater than 90% to meet the proposed standard; the presence of flue gas SO_3 in lignite-fired EGUs that can decrease Hg control efficiencies by half; and, challenges with balancing high temperatures at the heater exit that can further decrease Hg control efficiency up to 13% – make EPA's proposed Hg emission standard for lignite-fired EGUs of 1.2 lb/TBtu not achievable.

Response 4: The impact of coal sulfur content and SO_3 is discussed in section V.D of the preamble.

Comment 5: Commenters stated that the EPA has not completed the initial task of determining whether lignite units are able to achieve 1.2 lb/TBtu. They said once feasibility is determined (assuming it is feasible), the means of achieving 1.2 lb/TBtu with a compliance margin must be determined. The commenters said that then, costs may be assigned to that control strategy. They said that none of these steps have taken place.

Response 5: The EPA has shown that there are EGUs in the "lignite-fired EGU" subcategory that have demonstrated an ability to meet the 1.2 lb/TBtu Hg emission limit while firing on lignite coal. Further, the EPA has indicated that there are numerous ways that EGUs that are firing non-lignite coals are meeting that standard. Indeed, the existing lignite-fired EGUs are currently employing a variety of control strategies (chemical additives, liquid sorbents, activated carbon injection, brominated sorbent injection, *etc.*).

Comment 6: Commenters stated that Sargent and Lundy (S&L) identified the following missing components that would be needed to calculate cost: (1) Demonstration testing to determine feasibility; (2) A PAC dosage rate determined during testing; (3) A guaranteed injection rate from vendors; and (4) the role of the Hg content variability of the lignite to define an appropriate compliance cushion. They asserted that none of these steps were taken by the EPA, and a 60-day comment period is obviously insufficient for sources to obtain this data and information. The commenters said that the EPA has not adhered to its initial burden of identifying what is feasible, instead causing sources to scramble to "prove a negative" during a condensed comment period.

Response 6: The EPA has provided a cost estimate to meet the 1.2 lb/TBtu emission standard in the 2023 Proposal supporting materials and has provided an updated cost estimate in the 2024 final rule and supporting materials (see the 2024 Technical Memo) and has found the costs to be reasonable.

Comment 7: Commenters stated that the EPA's substantial Hg limit reduction for lignite units is unjustified. They said that the EPA proposes to effectively eliminate the low rank coal subcategory established for lignite-powered facilities by lowering the Hg standard to 1.2 lb/TBtu. The commenters said that the EPA justifies this revision by finding that "available controls and methods of operation . . . will allow lignite-fired EGUs to meet the same Hg emission standard that is being met by EGUs firing on non-lignite coals." The commenters said that the EPA also finds that the costs of meeting the same standard as other EGUs is reasonable. Commenters took issue with both of these conclusions.

Commenters stated that S&L examined the feasibility and cost of MRY Unit 2 to attain the newly proposed limit of 1.2 lb/TBtu. The commenters said that S&L was able to conclude the following within the 60-day comment period:

- Units firing lignite coal with lower heating values have to accommodate frequently changing coal quality and require a wide range of flexibility to account for instances of firing high Hg seams of coal to consistently achieve required Hg emissions.

- The Young Station's lignite coal supply has a wide range of Hg content between 0.053 ppm and 0.184 ppm, which results in projected Hg emissions between 4.79 lb/TBtu and 17.42 lb/TBtu. A considerable operating margin is needed to allow for consistent adjustments.
- Documented evidence of a lignite unit achieving 1.2 lb/TBtu or below has not been found/reviewed.
- The existing equipment on MRY Unit 2 may not be able to achieve the recently proposed 1.2 lb/TBtu Hg limit for lignite fired units.
- Demonstration testing would be required to determine a PAC dosage rate, guaranteed injection rate, and the emissions rate that can be achieved when considering the Hg content variability of the lignite.
- Additional modifications to MRY Unit 2's control system may be required that cannot be determined at this time; however, it is likely that the existing lances and transport piping would need to be replaced to accommodate a higher injection rate.

Response 7: The EPA has acknowledged the variability in Hg content for North Dakota lignite. However, the owner/operators of other EGUs firing non-lignite fuels (subbituminous coal, eastern and western bituminous, anthracite, coal refuse, *etc.*) also experience a wide range of Hg content. As shown in Table 3 in the preamble for the final rule, the EGUs firing lignite from Texas and Mississippi experience fuel with much higher Hg content and greater variability. Twin Oaks units 1 & 2 (firing Texas lignite) have consistently demonstrated the ability to meet an emission standard of 1.2 lb/TBtu (or lower) and Red Hills units 1 & 2 (firing Mississippi lignite) have reported Hg emissions very near 1.2 lb/TBtu. Non-lignite coals in Kentucky (mostly bituminous), Pennsylvania (mostly bituminous), and Wyoming (mostly subbituminous) all show variability – in fact, coals mined in Pennsylvania had a higher average Hg content (14.5 lb/TBtu) and a wider range of variability (0.1 – 86.7 lb/TBtu) than the average Hg (9.7 lb/TBtu) and variability (2.2 – 62.1) of lignite mined in North Dakota. The EPA understands that some modifications to existing control technology may be needed to meet the revised emission standard. Accordingly, the EPA is allowing up to 3 years for sources to come into compliance with the revised standard. Under certain circumstances, sources may request an additional year from their permitting authority for the installation of controls.

Comment 8: Commenters stated that the EPA has a legal obligation to ensure all standards are "achievable." The D.C. Circuit interprets achievable to mean "capable of being met under most adverse conditions which can reasonably be expected to recur." (White Stallion Energy Center, LLC v. EPA.) The commenters said that the EPA's analysis falls short based on the lack of testing data and misguided assumptions.

Commenters stated that as S&L notes, there is no Hg test data available to demonstrate that lignite units can achieve 1.2 lb/TBtu. They said this fact alone calls the EPA's analysis into question. The commenters said that while courts have not required the EPA to present test data, the EPA must rely on a reasonable assumption, presented in the record, that the standard can be achieved, but does not present such an assumption.

Response 8: Commenters have claimed that Hg control from lignite-fired EGUs is challenging because the Hg content of lignite is high and variable – but EGUs firing non-lignite coals also experience fuel with high Hg content and variable content. Commenters have claimed that the low halogen content coupled with highly alkaline ash makes it challenging to capture Hg from lignite-fired EGUs – but EGUs firing subbituminous coal face the same challenge. Commenters have claimed that SO_3 in the flue gas of lignite-fired EGUs challenges the ability of such sources to effectively control Hg – but SO_3 is typically much more of an issue for EGUs firing higher sulfur bituminous coal and the EPA has noted multiple control technology vendors that offer "SO_3 tolerant" sorbents and other control technologies to overcome that challenge. EGUs firing non-lignite coal with high variability Hg content, high SO_3 in the flue gas, low natural halogen and high alkalinity – eastern bituminous coals, western bituminous coals, subbituminous coals, waste coals, anthracite, etc. all must meet an emission limit of 1.2 lb/TBtu despite the "adverse conditions" created by each of these challenges. The EPA has also noted that Twin Oaks units 1 & 2 – firing Texas lignite – have demonstrated the ability to meet or exceed the 1.2 lb/TBtu.

Comment 9: Commenters stated that the EPA's rationale for changing the lignite emission limit was that activated carbon performance has improved since 2011 and currently some lignite units are meeting the 4 lb/TBtu limit with apparently low levels of Hg removal. The commenters said thus, there is room to increase Hg removal in lignite units.

Commenters stated that Staudt's analysis of data for lignite Hg emissions showed an inverse relationship between Hg emission rate and estimated Hg capture. The lowest emission rates (1-1.25 lb/TBtu) were associated with the highest estimated Hg capture (85% – 88%). The commenters said that the highest emission rates (~3.8 lb/TBtu) were associated with 57% – 58% estimated Hg capture - that is, the worst-performing units were operating with low Hg removals that are very much less than possible with state-of-the-art control technologies and less than removal levels demonstrated by the best-performing units. The commenters said that the majority of the low-rank virgin coal units already use ACI and could increase their treatment rate to achieve higher Hg capture rates and that Staudt estimated that an emission limit of 1 lb/TBtu for lignite-fired units would require less than 95% capture in every case, and in most cases much less.

Response 9: The EPA acknowledges these comments and agrees that there is room to increase the Hg removal in lignite units.

Comment 10: Commenters stated that the Hg inlet numbers utilized in the proposed rule appear to be underestimated and said Fort Union lignite (ND and MT) and Gulf Coast lignite (TX and MS), as reported by USGS in Fact Sheet FS-095-01, are indicated at 14 lb/TBtu and 27 lb/TBtu, respectively. The commenters said that using the values indicated by the USGS, 2021 removal would be 80% – 90% and with the higher Hg inlet numbers, 92% – 98% reduction in the Hg content would be needed to achieve a 1 lb/TBtu. They said as indicated above, Hg reduction is an inverse relationship between treatment and removal. As the Hg content is reduced, the opportunity for a Hg molecule to become captured by a sorbent is decreased or becomes more challenging. The commenters said that the proposed lower Hg compliance rates may require substantially more chemical to be applied for treatment of the emissions. The commenters said furthermore, given the specific mechanisms involved in Hg capture, it is possible that Hg reduction may be maximized and 1.2 lb/TBtu or lower may not be achievable, in practice.

Commenters stated that the EPA also assumes that lignite units can achieve 1.2 lb/TBtu using halogenated carbon. Although the Young Station does not use this product, another North Dakota lignite facility is already using it. These units observe variability and declining reductions with the increase of injection rates. This North Dakota facility is using more PAC than the EPA assumes in its analysis.

Commenters stated that their units further underscore the variability of Hg levels in lignite coals. Commenters observed potential operational concerns that their relatively new Hg control system will have to achieve such a low rate, given the challenges of reducing Hg in lignite coals due to the correlation curve.

Response 10: The EPA has updated the Hg content of coals as discussed in the preamble for the final rule and in a supporting technical memorandum titled "1998 ICR Coal Data Analysis Summary of Findings" available in the rulemaking docket at EPA-HQ-OAR-2018-0794.

Comment 11: Commenters stated that the EPA significantly underestimated the cost of additional Hg controls. They said that the current Hg control system at Coal Creek was designed to control to the existing 4.0 lb/TBtu Hg limit, using both a halogenated coal additive in conjunction with a chemical added to the wet FGD reaction tanks, and REC estimates that Coal Creek currently removes approximately 260 lb of additional Hg per unit at a cost of approximately $1.25M per unit per year. The commenters said that importantly, the removal efficiency of Hg based on increased additives is not linear and at Coal Creek specifically, the high variability in inlet Hg concentrations has resulted in the halogenated chemicals used to maintain compliance with the current Hg limits to be applied at rates known to cause premature corrosion of major boiler components. The commenters said, for instance, since the MATS rule has been in effect, Coal Creek has seen significant increases in corrosion of boiler components and as an example has had to install ceramic coated air heater baskets and has had an increased amount of ductwork repair. They argued that examples like this have resulted in significantly increased outage and maintenance costs. Commenters believed the proposed limit of 1.2 lb/TBtu is unachievable with its current control system and that controlling Hg emissions further will require additional control equipment. Commenters stated that such costly controls are not warranted here, where the EPA's own analysis indicates that the remaining risks from the subcategory are not associated with Hg.

Response 11: The halogenated coal (*i.e.,* refined coal) has been used at many coal-fired EGUs, not just lignite-fired EGUs and others have expressed concern regarding increased corrosion from the use of chemical additives. Many owners/operators have indicated that they no longer use halogenated coal since the refined coal tax credit has expired. Pre-brominated (or pre-halogenated) sorbents can be added without release of the bromine (or other halogen) that contributes to the corrosion. The cost of the installation of the equipment needed to inject halogenated sorbents (*i.e.*, storage silo, injection system/lances, *etc.*) is small relative to the installation costs of other controls (*e.g.*, baghouse/FF, wet or dry FGD scrubber, SCR, *etc.*) and, the use of sorbents instead of chemical additives has the added potential to reduce corrosion and on-going component repair and replacement. Also, the more stringent Hg emission limit for lignite-fired EGUs is being revised from a CAA section 112(d)(6) technology review, not from a CAA section 112(f)(2) risk review.

Comment 12: Commenters stated that the costs of these revisions to the Hg standards are reasonable considering the industry's annual revenues, capital expenditures, and total expenditures. The EPA should consider costs in the context of what the power sector can absorb while continuing to serve its function of providing power. These costs are eminently reasonable in the context of the power sector's 2019 total expenditures of $242.9 billion and revenue of $401.738 billion. If the EPA strengthens the fPM standard to 0.0024 lb/MMBtu, the $166 million incremental cost of the Hg standards would be about 0.07% of the power sector's 2019 total expenditures, or about 0.04% of 2019 revenue. If the EPA strengthens the fPM standard to 0.006 lb/MMBtu, the $468 million incremental cost of the Hg standards would be about 0.19% of 2019 total expenditures or about 0.12% of 2019 revenue. These cost estimates are also small compared to power sector capital expenditures and within the range of historical variability in capital expenditures. These are clearly costs that the power sector can easily absorb while continuing to serve its function of providing power.

Response 12: The EPA acknowledge these helpful comments.

CHAPTER 5

5. Other proposed actions - technology review

Comment 1: Commenters stated that the EPA must consider the full range of technological developments that have occurred since the standards were originally promulgated. Commenters agreed that any of the types of developments that the EPA identifies in this proposal could necessitate strengthening standards, including: add-on control technologies, a process change or pollution prevention alternative, work practices or operational procedures, and any operational change or other factors not considered in the original rulemaking; improvements to controls that were identified and considered in the original rulemaking; and a significant change in the cost or cost effectiveness of controls. Commenters encouraged the EPA to expand this already broad list to include other factors, whether "developments" or not, that necessitate revisions, such as lower emissions rates and gained experience with monitoring. Commenters suggested that the EPA need not identify the incremental emission reductions that each development achieves; rather, that the Agency may point to the collective effect of developments, including lower emissions rates, to justify strengthening standards. The commenters said that this more holistic, inclusive view of the factors that may necessitate revisions to standards under CAA section 112(d)(6) aligns better with the statutory language, and that the EPA must consider all such factors in its reviews. They said, for instance, emission rates far below the current limits, coupled with identifiable improvements in control technologies, practices, and monitoring, present a compelling reason to lower the standards for each of the classes of HAP emitted by coal- and oil-fired power plants.

Response 1: The Agency agrees with commenters that we must consider the full range of technological developments since promulgation of the original standards. The Agency has provided its rationale for the final emission standards in section IV.D of the preamble.

Comment 2: Commenters stated that the EPA is justified in leaving Hg standards for non-lignite units, standards for IGCC units and oil-fired units, as well as acid gases and organic HAP unchanged, given that the Agency correctly concludes that there are no new technological advancements that would justify any updates to these standards. The commenters said that should the EPA seek to change any of these levels, the Agency must do so through a separate notice-and comment rulemaking process.

Response 2: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

5.1 No Revisions to Work Practice Standards for Organic HAP

Comment 1: Commenters agreed with the EPA that there are no new developments in technology or methods of operation that would result in cost-effective emission reductions and that Organic HAP work practice standards should be retained without change. Commenters noted that the periodic burner tune-ups required by the work practice standard are effective at ensuring good combustion.

Commenters stated that it is irrelevant whether the EPA believes there are "no developments that would result in cost-effective emission reductions of organic HAP." (88 FR 24882). Commenters asserted that the Agency's obligation to set numeric emission limits for power plants' emissions of dioxins, benzene, carbon disulfide, dichloromethane, and toluene is not conditional on the agency's beliefs about their cost effectiveness. Commenters said that where, as here, the EPA's existing emission standards for a source category fall short of the basic requirements for CAA section 112 emission standards, the EPA must fix such defects in its RTR for the category. (*La. Envtl. Action Network v. EPA*, 955 F.3d 1088, 1098 (D.C. Cir. 2020)).

Response 1: In the preamble, the EPA acknowledged it received a petition for reconsideration from environmental organizations that sought the EPA's reconsideration of organic HAP work practice standards. The EPA plans to continue its review and will respond to the petition in a separate action.

Comment 2: Commenters stated that the EPA must set numeric emission limits for toxic organic HAP. Commenters noted that when the Agency promulgated its original air toxics standards for power plants, it set work practice limits for all organic HAP they emit, including dioxins, claiming "the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods." (77 FR 9304, 9369), and as such, measurement of organic HAP emissions is "not practicable" under CAA section 112(h)(2) and, therefore, that it is "not feasible" to prescribe an emission limit for them (*Id.*). The commenters stated that the EPA has emissions data from at least fifty sites and that at least 50% of these data are above detection limits; per the EPA, 307 of the 322 power plants it modeled for its residual risk assessment, reported emissions of dioxins and polycyclic organic matter (POM) at levels high enough to support a risk assessment and demonstrate a cancer screening level greater than 1. The commenters said therefore, applying the EPA's own stated rationale for setting work practice requirements, it is "practicable" to measure emissions for dioxins, POM, benzene, carbon disulfide, dichloromethane, and toluene and therefore "feasible" to set numeric emission limits for them.

Commenters also noted that application of the emission measurement methodology is not "impracticable" just because emission measurements are below detection levels. Rather, in those circumstances, the emission measurement technology has been applied and has yielded measurements. Specifically, it is showing that emissions are below detection levels. They said such information allows the EPA to both set emission limits and implement emission limits, in the same sense that a very low or zero emission test result allows the EPA to do so, and the Agency has used non-detect results for these purposes in the past.

Commenters stated that the EPA's past argument that it "expect[s] organic HAP emissions are lower than the values from the 2010 ICR testing when the EPA concluded that it was not feasible to accurately measure organic HAP emissions because EGUs are now required to conduct periodic tune-ups and more efficient combustion leads to additional reductions in organic HAP" (EPA–HQ–OAR–2018–0794–4560, at 112 (Apr. 2020)) is irrelevant and misleading. The commenters said that because the record shows that application of measurement technology is practicable for at least some of the organic, the belief that organic HAP emissions are lower now than in 2010 is irrelevant. Commenters asserted that the EPA neglects to mention its own conclusion that the only work practice it established for organic HAP—periodic tune-ups—would not reduce emissions, and as such, the EPA's claim that organic HAP emissions are lower now than in 2010 is inconsistent with the agency's own statements in the record.

Response 2: As stated in the response above in this section, the Agency plans to review the organic HAP work practice standards in a separate action as part of a petition for reconsideration.

5.2 No Proposed Revisions to the Acid Gas Standards for Coal-Fired EGUs

Comment 1: Commenters expressed agreement with the EPA that no revisions to the standards for Acid Gas are necessary. Commenters said they are unaware of any cost-effective improvements that would result in further acid-gas emission reductions. The commenters said that if additional information leads the Agency to consider revised standards for acid gases or organic HAP, commenters requested that the EPA first propose such revised standards in a Supplemental Notice of Proposed Rulemaking or a separate Notice of Proposed Rulemaking and take comment on such proposed standards before adopting them.

Response 1: As no emission standards for acid gases or organic HAP were proposed or finalized, this comment does not require a response.

Comment 2: Commenters asserted that an HCl emission limit of 0.0006 lb/MMBtu could be achieved through improvements to wet FGD systems and DSI systems and noted the following:

- Costs of upgrading wet FGD systems, estimated at $43/kW (2019$), are well below the $100/kW that EPA assumed in its 2011 modeling (2009 dollars). Most units with wet FGD systems should be able to achieve HCl emissions rates of 0.0006 lb/MMBtu with little to no additional costs. They asserted that already some units are performing at rates of 0.0001 lb/MMBtu, which should be achievable for other units with wet FGD systems with additional upgrades.
- Emissions of acid gases specifically associated with already installed dry FGD systems decreased overall between 2011 and 2019. Costs of upgrading dry FGD systems, estimated to be as low as $17/kW, are well below the $100/kW that EPA assumed in its 2011 modeling. Costs have also come down as FF technology has improved, allowing for these components of the dry FGD to be smaller and less expensive. These upgrades could lower HCl emissions to a rate of 0.0006 lb/MMBtu with no further changes. The commenters said that however, based on data that EPA released with the proposed rule, no units equipped with dry FGD systems would need to make changes to achieve an HCl standard of 0.0006 lb/MMBtu.
- DSI systems now need less reagent or sorbent to achieve the same levels of acid gas reduction, partly because of advances in equipment and design of injectors that improve performance by better dispersing the reagent. Costs are lower than anticipated because FFs are typically not needed. These upgrades, on the order of $10/kW, could lower HCl emissions to a rate of 0.0006 lb/MMBtu. However, considering data that EPA released with the proposed rule, most if not all DSI-equipped units could achieve an HCl standard of 0.0006 lb/MMBtu by increasing sorbent injection rates, without making additional capital investments. Commenters asserted that the EPA does not need more information

on DSI rates to determine whether reductions in HCl and HF are feasible and cost-effective. Commenters stated that emissions data are available that would allow the EPA to calculate achievable reductions at each unit using DSI, or at a generic, model unit.

Commenters noted that per the Agency "[i]t is not clear that improvements in a wet or dry FGD scrubber would result in additional HCl emission reductions since HCl emissions are already much easier to control than SO_2 emissions", however, recent HCl and SO_2 emissions data from units equipped with wet FGD systems or DSI show a strong correlation between emissions rates for these two pollutants, and all units with dry FGD are already emitting below a rate of 0.0006 lb/MMBtu. The commenters said that therefore, data indicate that improvements to wet FGD or DSI systems that would reduce SO_2 emissions would also reduce HCl and HF emissions.

Response 2: The EPA acknowledges and thanks the commenters for providing these comments. We have taken these comments and the referenced information into consideration when establishing the final emission standards. The Agency did not propose to revise the acid gas emission standard for HCl or SO_2 in the 2023 Proposal (88 FR 24882). We have discussed the rationale for the final emission standards in section IV.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 3: Commenters stated that the incremental costs of achieving an HCl limit of 0.0006 lb/MMBtu are reasonable, especially when taking into account planned retirements and retirements that would likely already occur given the IRA, industry trends, and other regulations. They said the Andover Technology Partners' report—which does not account for retirements projected to occur under the IRA or cost reductions from FF installations to reduce fPM emissions—finds that coal-fired units could comply with this limit at an annualized cost of $191 million. The commenters said that the total cost is reasonable, as illustrated by comparisons to the industry's annual revenues (0.048% of 2019 revenue of $401.738 billion) and total expenditures (0.078% of 2019 total expenditures of $242.9 billion). If units implemented measures to meet a revised fPM limit, the incremental annualized costs to meet this acid gas limit would be even lower.

Response 3: The Agency thanks commenters for providing this additional information. The rationale for the final emission standards is discussed in section IV.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

Comment 4: Commenters urged the EPA to leverage the improvements to controls that will likely result from a strengthened fPM standard and secure further reductions in harmful acid gas emissions as well. The commenters said that the fact that most units with acid gas controls are already complying with an HCl limit of 0.0006 lb/MMBtu, while most units without such controls are not, suggests that this revised standard would better reflect the emissions levels achievable through measures that have been widely implemented and have proven cost-effective.

Response 4: The EPA acknowledges these comments. The rationale for the final emission standards is discussed in section IV.D of the preamble and in the 2024 Technical Memo entitled

“2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category.”

Comment 5: Commenters stated that the EPA should eliminate the coal refuse subcategory. The subcategory is not based on any design differences that could properly be used to identify a separate class, type, or size of coal-fired power plant and contrary to the EPA’s stated rationale that coal refuse contains exceptionally high concentrations of chlorine and sulfur, plants within the subcategory feature no design elements that require them to burn those high-HAP materials. The commenters said that the plants in the subcategory are capable of burning (and currently burn) fuels other than coal refuse such as low-sulfur coals that allow for compliance with the acid gas standards applicable to other plants. They said the Agency has identified no design features that render the plants in the subcategory incapable of meeting the general acid gas standards. The commenters said that furthermore, the acid gas standard established for the coal refuse subcategory does not reflect the maximum achievable reduction in emissions from those units and five of the six units within the subcategory have met enforceable SO_2 limits that are more stringent than EPA’s finalized standard for the subcategory and done so over a sustained period. Commenters asserted that the EPA’s acid-gas standard—set at the level of the worst performer in the subcategory—violates CAA section 112’s requirement that the EPA’s standards reflect the “maximum achievable reduction in emissions,” and be no less stringent than the emission reductions actually achieved by the best performing sources.

Commenters urged the EPA to lower the 2020 rulemaking compliance limit for the EBCR burning EGUs category. The commenters shared the concerns that these facilities are having negative effects on the air and water quality of Shenandoah as well as other nearby Class I areas and public lands.

Response 5: As noted by the commenters, the proposal did not address the acid gas standard for EBCR-fired EGUs. As such, these comments are outside the scope of the proposed action and no response is necessary.

Comment 6: Commenters found that developments since 2012 likely warrant strengthening the current 0.20 lb/MMBtu SO_2 surrogate standard. They said improvements in a wet or dry FGD scrubber would likely result in additional HCl emission reductions as the EPA’s use of SO_2 as a surrogate for acid gas emissions implies a direct relationship as indicated in its May 3, 2011 MATS proposal; therefore, as compliance with stringent SO_2 limits increase, then acid gas HAP emissions would decrease. Commenters recommended that the EPA consider Circulating Dry Scrubber (CDS) technology as a more-effective option for controlling SO_2. They said that a CDS FGD system has a similar installed cost to a comparable SDA FGD system. The commenters noted that it is likely that the EPA did not consider CDS as a control type in this action due to EPA’s use of CAMD which lumps CDS into the Dry Lime FGD category. The commenters asserted that if all affected EGUs were limited to 0.10 lb/MMBtu or less, annual emissions could be reduced by 56% (about 460,000 tons of SO_2/year).

Response 6: The Agency did not propose any changes to the SO_2 surrogate standard. The EPA will continue to review emission standards and other requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If, in the technology review, the Agency determines that modification of any emission standards is warranted, it will first propose revision to the standards and solicit comment on those proposed revisions.

5.3 No Proposed Revisions to Standards for Continental Liquid Oil-Fired EGUs

Comment 1: Commenters urged the EPA to retain the current definition of the limited-use liquid oil-fired subcategory and not impose new HAP standards on EGUs in this subcategory, given that there are already limits on the amount of fuel oil that can be burned. Commenters noted that the Agency has not identified any justification for the costs required for implementation and compliance with new HAP standards. They said any changes to the existing HAP standards for EGUs in this subcategory may lead to reliability issues, as these units are crucial to maintaining grid reliability during cold winter spells, other extreme weather events, or when natural gas is curtailed, as acknowledged by the Agency. Commenters provided the example of Winter Storm Uri in 2021, where the Public Utility Commission of Texas directed the development of a firm fuel product—now called "Firm Fuel Supply Service"— which incentivizes the addition and maintenance of alternative fuel capability at EGU facilities primarily fueled by natural gas resulting in securing 2,940 MW of alternative fuel capability from EGUs as part of its initial procurement of this service (https://interchange.puc.texas.gov/Documents/52373_336_1180125.PDF).

Response 1: The EPA's response to this comment is discussed in section VI.C of the preamble.

Comment 2: Commenters stated that testing liquid oil for HAP metals is theoretically possible. They said, however, based on their preliminary research, these tests are expensive and challenging to perform, and they found it difficult to find a laboratory that could do the analysis down to suggested levels.

Response 2: The EPA acknowledges and thanks the commenters for providing these comments. We have taken these comments and the referenced information into consideration when establishing the final emission standards.

5.4 No Proposed Revisions to Standards for Non-Continental Liquid Oil-Fired EGUs

Comment 1: Commenters stated that the EPA should not impose new HAP standards for EGUs in non-continental areas because any additional standards would require large investments to achieve compliance, divert investments away from renewable energy development, or force premature retirement — of which the latter may jeopardize resilience and reliability in these areas. Other commenters also stated that the proposal is justified given the incredibly low utilization of these units, which are reliability critical assets, and which are likely to be retired and replaced by flexible fuel units in coming years.

Response 1: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

Comment 2: Commenters requested that the EPA not require oil-fired EGUs in non-continental areas to switch from residual oil to cleaner fuels. Any change to distillate fuel would be cost-prohibitive as natural gas may not be physically accessible or otherwise consistently acquired in non-continental areas. Commenters asserted that a switch to distillate oil would increase fuel costs by at least 7%, resulting in an approximate increase of $61 million per year (without accounting for inflation or grid changes). They said, additionally, the EPA should not require liquid oil-fired EGUs in non-continental areas to switch to cleaner fuels after a certain number of hours of operation. The commenters said that this would force EGUs to undertake significant modifications to plant infrastructure to support two different types of fuel oil. Modifications, such as building additional fuel oil storage tanks, which may be difficult at facilities located in urban areas where there is insufficient land available for such an expansion on the site's footprint. Commenters noted that diverting large capital outlays to such modifications would not be fiscally sound, particularly in areas with aggressive Renewable Portfolio Standards (RPS). For instance, Hawaii's RPS requires electric generating companies to sell increasing percentages of electricity generated from renewable sources, where the percentage must reach 40% by 2030, 70% by 2040, and 100% by 2045. The commenters said that owners and/or operators of EGUs in these areas would thus need to outlay significant investments for both endeavors — complying with any changes to their MATS requirements while simultaneously meeting the RPS — and the costs required for both would ultimately need to be passed down to customers, further increasing electricity costs, which already are nearly three times higher than the average in the continental U.S.

Response 2: The EPA acknowledges and thanks the commenters for providing these comments. We have taken these comments and the referenced information into consideration when establishing the final emission standards. We have discussed the rationale for the final emission standards in section IV.D of the preamble.

Comment 3: Commenters requested that the EPA not eliminate or revise the fPM standard because for non-continental liquid oil-fired EGUs, the fPM standard is crucial to simplifying the monitoring requirements and, more importantly, reducing the costs associated with ongoing MATS compliance. The cost of performance testing to demonstrate compliance with the surrogate fPM standard is much lower than the cost of performance testing to demonstrate compliance with the numerous standards for individual non-Hg HAP metals, as well as for total non-Hg HAP metals. The commenters said that requiring monitoring and testing for each individual non-Hg HAP metal would significantly increase compliance costs and, thereby, electricity rates. Commenters noted that, for example installing Hg, HCl, HF, and PM emission controls on its non-continental MATS-applicable fleet to comply with the current MATS for continental oil-fired EGUs is estimated to cost nearly $1 billion. Commenters added that unlike many states in the continental U.S., there is excellent natural air quality in remote island locations due to geographical isolation, island configuration, and trade winds and as such, any emission reductions achieved by amending the existing MATS standards likely would have only a de minimis impact on air quality, and the cost of complying with any amendments would be vastly disproportionate to their benefits.

Response 3: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

5.5 No Proposed Revisions to Standards for IGCC EGUs

Comment 1: Commenters expressed agreement with retaining the emission standards for IGCC and oil-fired EGUs.

Response 1: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

CHAPTER 6

6. Other proposed actions

Comment 1: Commenters stated that EPA could also contextualize HAP emission reduction benefits within the context of cumulative pollution burdens which could make incremental emission reductions lead to more significant risk reductions. They said for example, HAP emissions from these power plants alone may not exceed EPA's "acceptable" risk thresholds, but they might exceed the threshold when combined with cumulative burden from other sources. The commenters said that communities that bear a disproportionate burden of environmental harms may benefit from revisiting the environmental justice analysis.

Response 1: EPA is required to provide the risk information necessary to inform RTR regulatory decisions and, to this end, the EPA conducts a comprehensive assessment of the risks associated with exposure to the HAP emitted by the source category and supplements that with additional information that is available about other possible concurrent and relevant risks. While the incorporation of additional background concentrations from the environment in our risk assessments (including those from mobile sources and other industrial and area sources) could be technically challenging, they are neither mandated nor barred from our analysis. In developing the decision framework in the Benzene NESHAP that is currently used for making residual risk decisions, the EPA rejected approaches that would have mandated consideration of background levels of pollution in assessing the acceptability of risk, concluding that comparison of acceptable risk should not be associated with levels in polluted urban air (54 FR 38044, 38061, September 14, 1989). Background levels (including natural background) are not barred from the EPA's ample margin of safety analysis, and the EPA may consider them, as appropriate and as available, along with other factors, such as cost and technical feasibility, in the second step of its CAA section 112(f) analysis. This assessment excludes background contributions because the available data are of insufficient quality upon which to base a meaningful analysis. Further, our approach here is also consistent with the approach we took regarding this issue in the Hazardous Organic NESHAP (HON) RTR (71 FR 76603, December 21, 2006), which the court upheld in the face of claims that the EPA had not adequately considered background concentrations. (NRDC v. EPA, 529 F.3d 1077 (D.C. Cir. 2008)).

Comment 2: Commenters stated Coal Creek anticipates playing a crucial role in North Dakota's aggressive goal of being carbon neutral by 2030 and reducing the carbon intensity of power delivered in the MISO region. The commenter said that there are plans to install 400 MW of wind at Coal Creek and there is active work with the Energy and Environmental Research Center at the University of North Dakota towards the installation of a full-scale post-combustion CO_2 carbon capture system designed to capture 95% of CO_2 emissions at the facility.

Response 2: The EPA acknowledges and thanks the commenters for providing these comments. We have taken these comments and the referenced information into consideration when establishing the final emission standards. The rationale for the final emission standards is discussed in section IV.D of the preamble and in the 2024 Technical Memo entitled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category."

6.1 Startup Requirements

Comment 1: Commenters stated the use of the four-hour startup definition should continue to be allowed. They said the EPA's determination that only eight EGUs are currently using that option is insufficient justification for eliminating the definition. Given that the 2023 Proposal does not identify any flaws with the current definition, the EPA should explain why elimination of the four-hour definition from MATS is appropriate when there are units currently relying on it. Commenters also stated that the EPA should consider providing reasonable exemptions for the EGUs that currently use that definition, thus gradually phasing out the definition without imposing any additional compliance burdens. The commenters also argued that with potentially lower fPM standards, more facilities may need the additional flexibility allowed by this definition of startup as their margin of compliance is shrunk. They noted startup or non-steady state operation is not conducive to CEMS accuracy and may create false reporting of emissions data biased either high or low depending on the actual conditions.

Commenters stated several facilities are currently required to use the four-hour startup definition per federal consent decrees or state agreements. They said such a scenario provides clear justification for a limited exemption, as MATS compliance should not result in an EGU violating its consent decree. Commenters noted other scenarios where state permits have special conditions with exemptions from emission limits during ramp-up or ramp-down periods. They said many facilities alleviate high initial emissions by using alternate fuels to begin the combustion process, which has been demonstrated as a Best Management Practice and to lower emissions. Commenters noted that the permit modification process, let alone any physical or operational modifications to the facility, could take significantly longer than the 180-day compliance deadline, depending on public comments, meetings, or contested hearing requests made during the permit process.

Commenters stated the second part of the startup definition has seen limited use due to the additional reporting requirements that the EPA imposed on sources that chose to use the definition, which are unnecessary and should be removed from the rule. The commenters said that the analysis the EPA conducted during the startup/shutdown reconsideration showed that the definition was reasonable, and one could argue that it may be especially needed if the EPA further reduces the limits given the transitory nature of unit and control operation these periods.

Commenters stated the second paragraph of the startup definition should remain in the rule as removing this for simplicity is not an adequate justification. They said the EPA is conflating the MACT standard-setting process with this RTR process. Though the EPA notes the best performing 12% of sources do not need this alternative startup definition, commenters stated this change is beyond the scope of the technology review.

Commenters stated that the EPA should consider allowing the use of diluent cap values from 40 CFR part 75. As these are limited under MATS, commenters noted startup and shutdown variations are more pronounced than if diluent caps were to be allowed. They said that with a lower emissions limitation, the diluent cap would mathematically correct for calculation inaccuracies inherent in emission rate calculation immediately following startup.

Commenters stated the second paragraph of the startup definition is beneficial to units that require extended startups. They said including allowances for cold startup conditions could allow some EGUs to continue operation until more compliant generation is built, which would help facilitate a smooth transition to newer plants that meet the requirements without risking the reliability of the electric grid. Commenters also noted some control devices, such as ESPs, may not be operating fully even when the plant begins producing electricity.

Commenters stated RATA must be conducted at greater than 50% load under 40 CFR part 60 and at normal operating load under 40 CFR part 75. They said that it is not reasonable to require facilities to certify their CEMS at greater than 50% capacity and use it for compliance at less than 50% capacity. Commenters stated that startups have constantly changing flow and temperatures that do not allow compliance tests to be conducted during these periods.

Response 1: The Agency has responded to this comment in section VII.C of the preamble. PM CEMS are not subject to RATAs and as the Agency did not propose changes to HCl CEMS, the comment on RATAs being conducted at greater than 50% load is moot.

Comment 2: Commenters stated the EPA should finalize its proposal to remove the unlawful definition of startup that allows excess emissions during this period. The commenters stated that the EPA must remove the second paragraph of the startup definition as there is no legal basis under CAA section 112(h) for a work practice standard in lieu of a numerical limit during this period. The commenters said that the CAA only allows work practice standards in two specific, very limited situations, only one of which EPA relied upon to establish the extended startup period here—when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." (42 U.S.C. § 7412(h)(2)). That the vast majority of coal-fired EGUs have chosen the first startup definition shows that it is practicable to measure emissions during the four hours in question. The commenters said that as during the 2012 MATS Final Rule, the EPA is again taking the position that the length of startup should be based on what the best performers can achieve when it should seek to ensure the source category as a whole measure their emissions during the four hours in question. The commenters said that if the EPA were to take the position that each and every EGU must be able to measure its emissions during the extended startup period before requiring compliance with numeric standards during these four hours, that position would be contrary to the plain language of the statute, which only allows the EPA to establish work practice standards due to inability to measure emissions when measurement is not practicable for a "particular class of sources."

Commenters said that the small number of EGUs that have chosen the second definition do not constitute a "particular class of sources." (42 U.S.C. § 7412(h)(2)(B)). They argued that the EPA has also never suggested that CAA section 112(h)'s other avenue for promulgating work practice standards—when "a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or [when] any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State or local law" (42 U.S.C. § 7412(h)(2)(A))—applies during the first four hours of electricity generation. They said nor could the EPA: HAP from EGUs can be and are emitted through units' stacks (the conveyances designed and constructed to emit such pollutants), and no requirement for or use of EGU stacks would be inconsistent with any federal, state, or local law.

Commenters said that because there is no statutory basis for work practice standards during the four hours in question, the EPA must remove the extended startup period and impose numeric standards during those four hours. They said further that there is no statutory basis for the extended startup period makes it “necessary” (42 U.S.C. § 7412(d)(6)) under CAA section 112(d)(6) to remove this extended work practice period.

Commenters stated compliance with the numeric standards beginning at electricity generation is consistent with the EPA’s Acid Rain Program, which—for more than two decades— has required all EGUs to measure emissions using CEMS any time units are combusting fuel, including the first four hours of electricity generation, and count those emissions for compliance purposes. They said that the EPA has attested to the accuracy of that Acid Rain emissions data in its Plain English Guide to the program’s monitoring regulations: “Part 75 . . . [e]nsur[es] that the emissions from all sources are consistently and accurately measured and reported. In other words, a ton of emissions from one source is equal to a ton of emissions from any other source.” (EPA, *Plain English Guide to the Part 75 Rule*, at 6 (June 2009)). The commenters said similarly, the Agency’s Policy Manual for these monitoring requirements states: “To ensure that allowances are consistently valued and . . . all of the projected emission reductions are in fact achieved, it is necessary that actual emissions from each affected utility unit be accurately determined. To fulfill this function, Title IV requires that affected units continuously measure and record their SO_2 mass emissions.” (EPA, *Part 75 Emissions Monitoring Policy Manual*, at iii (2013)).

Commenters stated that eliminating the extended startup period is necessary under CAA section 112(d) because removing it would achieve emission reductions. They stated that startups can take place many times every year – for example, the EPA found that the “average EGU had between 9 and 10 startup events per year during 2011 – 2012, but data from a small number of EGUs indicated significantly more startup events (*e.g.,* the EGUs with the most startup events had over 100 startup events in 2011 and over 80 in 2012).” (EPA–HQ–OAR–2009–0234–20451, at 4 (Nov. 2014)). The commenters said that more recently, the National Association of Regulatory Utility Commissioners (NARUC) found that the average coal-fired EGU had 10.64 startups in 2018. They said that emissions from EGUs that choose the second startup definition can be elevated during the extended startup period because the applicable work practice standards allow EGUs to burn dirty fuels such as coal and not operate their pollution controls at all (for non-particulate controls) or not operate them at levels that would fully reduce emissions (for ESPs for particulate control). The commenters said that when ESPs are not fully operational while coal is being fired during startup, particulate emissions could be roughly 10 to 100 times higher than they would be if this pollution control equipment fully operative. The commenters said this is especially important because, as coal-fired EGUs are forced into more and more intermittent use by less expensive gas-fired units and renewable energy, the amount of cycling and number of (at least cold) startups will likely increase. They asserted that even the worst performers should have no trouble meeting MATS beginning at generation, since those standards generally have a 30-day averaging period.

Commenters stated removing the extended startup period promptly would be administratively efficient, since—as EPA recognizes in the proposed rule here—the D.C. Circuit’s decision in

Chesapeake Climate Action Network requires the Agency to conduct 42 U.S.C. § 7607(d)(7)(B) reconsideration proceedings concerning environmental groups' objections that there is no valid basis for the extended startup period. The commenters said that if the EPA were to finalize its proposal to remove the extended startup period, there would be no need to conduct separate reconsideration proceedings.

Commenters stated that the extended startup option should be removed as cost is irrelevant because the EPA has no valid statutory basis for retaining the extended startup period and cost is irrelevant in the context of EPA's CAA section 112(d)(6) review of this issue because it is "necessary" to revise MATS to correct a legal defect—that MATS allows compliance with work practice standards even though the CAA instead requires numeric standards during all of the extended startup period. They said that nevertheless, the EPA is correct that removing the extended startup period "would result in little to no additional expenditure since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the definition of 'startup' were more expensive than the requirements of paragraph (1) of the definition of 'startup.'" The commenters said that further, the fact that the overwhelming majority of EGUs have chosen the first definition makes clear that measuring emissions during the extended startup period is not cost-prohibitive.

Commenters stated removing the extended startup period now is also important because the EPA characterized the 2014 startup definition as a stopgap and asserted—both in the administrative record and in the D.C. Circuit—that it would assess whether to maintain this work practice period during the RTR. They said in fact, the EPA vowed to the D.C. Circuit that it would consider removing the four-hour extended startup work practice period from the NESHAP for industrial boilers (a period that was based primarily on when EGUs can purportedly begin to measure emissions) in exactly the circumstances that are present here—when operators choose and comply with the first startup definition.

Response 2: The Agency appreciates the commenters' support for removing startup definition #2, even though the Agency disagrees that the definition is unlawful or unavailable as a work practice standard. Moreover, in contrast to the commenters' suggestion, the Agency maintains that emission measurements during periods of startup – as well as shutdown and certain malfunctions – are not practicable. This view is consistent with that already explained and contained in the *Denial of Petitions for Reconsideration of Certain Startup/Shutdown Issues: MATS*, available in the MATS docket at EPA-HQ-OAR-2009-0234-20581 and in the *Startup and Shutdown Technical Support Document*, available in the MATS docket at EPA-HQ-OAR-2009-0234-20427.

The Agency continues to disagree with the commenters' contention to equate the acid rain program and its requirements contained in 40 CFR part 75 with those of this program and its requirements contained in 40 CFR part 63. As explained earlier in this document and in the aforementioned *Denial of Petitions for Reconsideration of Certain Startup/Shutdown Issues: MATS*, available in the MATS docket at EPA-HQ-OAR-2009-0234-20581, the commenters err by failing to acknowledge that the distinct measurement techniques necessary for an emissions trading program, such as that contained in the acid rain program, established under title IV of the Clean Air Act Amendments (CAAA), allows source owners or operators to purchase credits for emissions in excess of an annual threshold and differ from those found in continuous emissions compliance programs, which contain never-to-be exceeded emission limits, such as those established under section 112 of title I of the Clean Air Act. Moreover, the commenters continue to misunderstand the purpose of the Agency's analysis of the startup data obtained from the acid rain program: that analysis was conducted to determine the end of startup based on when controls were engaged, not to assess the accuracy of emission measurement at the beginning the startup period.

While the Agency will remove startup definition #2 from the rule and is taking action consistent with the D.C. Circuit's direction in *Chesapeake Climate Action Network v. EPA* by taking comment on the proposal to remove this definition, 952 F.3d 310 (D.C. Cir. 2020) as the commenters' desire, the Agency does not necessarily agree with the commenters' claims concerning the potential magnitude of emissions from not fully engaged control devices. Moreover, because work practice standards, not emission standards, are in place during periods of startup, the Agency lacks data to determine and does not agree with the commenters' incorrect assertion that startup emissions may not be problematic since they can be included in 30-boiler operating day rolling averages.

6.2 Removing Non-Hg Metals Limits

Comment 1: Commenters urged the EPA to retain the non-Hg metal HAP limits and associated testing option under MATS. While fPM is a suitable surrogate for non-Hg metal HAP, and thus the EPA was and is justified in setting a standard for fPM under MATS, it is incongruous for EPA to eliminate the standards for the pollutants that are actually the subject of CAA section 112(d)(6) – the non-Hg metal HAP. The commenters said that the EPA offers no substantive reason for eliminating the actual HAP standards and that removing the individual and total non-Hg metal standards untethers the reduction of non-Hg metal HAP standards from the fPM emission limits. The commenters said that here, removing the individual and total non-Hg metal standards appears to confirm that the purpose of this Proposed Rule under CAA section 112(d)(6) is, in truth, to effect reductions in fPM, regardless of any reductions in the pollutants of interest – the HAP.

Commenters stated although few EGU owners have chosen to demonstrate compliance with the non-HG metal HAP standards, these EGUs presumably selected that for a reason. They said that no matter how justified a surrogate is, there will be situations in which the underlying HAP – the pollutant of real interest – may not follow the generally applicable correlation between the HAP and the surrogate that the fPM standard is based upon. The commenters said that for example, on scrubbed sources, the PM is mostly potential limestone slurry or gypsum carry-over rather than coal ash, which is largely removed by other control equipment and the supplemental removal by being "washed out" by the scrubber. The commenters asserted that if the PM is low, it is certainly an indication that the metals have been captured somewhere, but higher PM concentration due to issues with the scrubber mist eliminators might not suggest higher non-Hg metal emissions and direct Method 29 testing would be a better indicator of performance than PM. The commenters said that for that reason, the EPA should retain the flexibility for EGUs to meet either the fPM or individual/total non-Hg metal HAP standards.

Commenters stated that the suggestion that weekly non-Hg metals testing might be needed is nonsense. They said that the EPA has suggested that "very frequent emissions testing, perhaps on the order of weekly" might be needed if "our proposal to remove non-Hg metals from the rule not finalized" in order "to provide more information on compliance status." (88 FR 24886). The commenters said that quarterly PM or metals testing, which the EPA categorized as frequent in the original rulemaking, is adequate to show compliance in conjunction with the other monitoring required under other rules to ensure proper operations of controls. They argued that imposing more frequent testing would be unnecessary, costly, and impractical, particularly given the changing dispatch of coal-fired EGUs.

Commenters stated the EPA should not remove the LEE option for fPM and non-HG HAP metals. The commenters said that the EPA is proposing to remove the LEE option for fPM and non-Hg HAP metals because requiring PM CEMS would render the current stack testing compliance method for the LEE program "superfluous." If the EPA establishes the final fPM standard at 0.010 lb/MMBtu, the Agency should nonetheless retain the LEE option and allow LEE to continue demonstrating compliance through stack testing (without any changes to the current test frequency). The commenters said that stack testing via the three-year cycle after meeting the LEE limit is much less costly than quarterly testing and thus, units that currently rely on the LEE provisions would face an exponential increase in monitoring costs associated with installing, implementing, and using PM CEMS, including employing additional technicians to operate the equipment.

Response 1: The response to these comments is provided in section IV.D of the preamble. Additionally, as mentioned earlier, because a non-Hg metals LEE program was not proposed, consideration of a non-Hg metals LEE program is moot.

Comment 2: Commenters expressed support of continued reduction in emissions of non-Hg HAP metals under the recommended revisions. They said that in the 2012 MATS Final Rule, the EPA determined that non-Hg metals like chromium and nickel, emitted by power plants as particulates, pose cancer risks, and that power plants continued to be a significant source of these and other toxic metals, such as arsenic and cadmium, which have serious health effects. The commenters said that in 2012, the EPA studied the chronic inhalation risk from HAP other than Hg emitted by a small subset of potentially regulated facilities and found that nickel, hexavalent chromium, and arsenic emissions posed serious risk. A 2023 literature review illustrates the growing evidence of the significant adverse health effects from exposures to both individual metals and groups of non-Hg metals in air pollution. The commenters said researchers now better understand than at the time MATS was promulgated how exposure to multiple metals in addition to other air pollutants impairs human health more severely than exposure to metals individually. The commenters said that this reinforces the need to set a stringent emissions standard to protect communities from these dangerous pollutants. They concluded that cumulative health risks of exposures to HAP metals and mixtures of metals from multiple sources and multiple exposure pathways bolsters the EPA's proposal to strengthen the standards for non-Hg metals emitted from EGUs.

Response 2: As already established by the original MATS rulemaking, the Agency determined that fPM is an appropriate standard for non-Hg metals. Therefore, the Agency agrees with commenters' assertion and will reduce the current fPM emissions limit by two-thirds. Regarding non-Hg metal HAPs, EPA is aware that new scientific information has become available since the current health benchmarks for nickel, hexavalent chromium and arsenic were developed. It is premature to estimate what, if any, revisions to the IRIS assessment for these metals may be needed until a comprehensive evaluation is conducted. At time of writing, the IRIS assessments for hexavalent chromium and inorganic arsenic are still underway. More detailed information on the IRIS assessment development process is available on the IRIS website.

Regarding cumulative risks, we disagree with the comment that we failed to consider or account for cumulative risk. The individual cancer risks for each source category were aggregated for all carcinogens. In assessing noncancer hazard from chronic exposures for pollutants that have similar modes of action or (where this information is absent) that affect the same target organ, we aggregated the hazard quotients. This process creates, for each target organ, a target-organ-specific hazard index (TOSHI), defined as the sum of hazard quotients for individual HAPs that affect the same organ or organ system. All TOSHI calculations presented here were based exclusively on effects occurring at the "critical dose" (*i.e.,* the lowest dose that produces adverse health effects).

Comment 3: Commenters stated that the removal of the option to report HAP metals directly could inadvertently overlook the presence of vapor-phase metals, such as SeO_2, or metals present in extremely small PM. They said this could potentially lead to an inaccurate estimation of actual metal HAP emissions and urge the EPA to continue to include the option for facilities to monitor metals directly. The commenters said they are currently working with the EPA in a Small Business Innovation Research Project to develop a method to allow for continuous or semi-continuous non-Hg metals monitoring. They said their innovative approach holds promise in terms of providing direct measurement of speciated and total metals, while EPA Method 29 only provides intermittent data, and the PM surrogate does not provide metals data at all.

Response 3: As established by the original MATS rulemaking, the Agency determined that fPM (and acid gases for vapor phase selenium) is an appropriate surrogate for non-Hg metals. Therefore, the Agency disagrees with the commenters' assertion that non-Hg metals limits are needed as a check on vapor phase metals emissions.

Comment 4: Commenters stated that CAA section 112(d)(3) requires the EPA to set standards for existing sources based on the emission averages of the best performing 12% of current facilities. Further, CAA section 112(d)(6) requires that the EPA review and revise these standards at least every 8 years. They said; thus, it is clear that Congress intended the EPA to periodically adjust emissions standards as industry standards improved. Commenters stated that for the Agency to accurately revise the standards for HAP metals, the EPA needs to monitor for HAP metals emissions directly to better understand how the "best performers" reduce HAP metal emissions or prevent HAP metal emissions from increasing. They said, that is, the efficacy of various HAP metal emission reduction/prevention options cannot be assessed unless each HAP metal is measured because each has unique and wide-ranging chemical and physical properties dictating their presence and behavior under various conditions. The commenters argued that this will be particularly important if processes and/or chemistry changes through the addition of reactants to facilitate other aspects of the process such as minimization of corrosion and catalyst poisoning, enhancement of collection efficiency of other species such as Hg.

Commenters stated that failure to monitor HAP metals directly will significantly impair the EPA's ability to revise emissions standards in the future and would not be consistent with the intent of the CAA to ensure that emissions standards are updated every 8 years based on improvements that the best performers have implemented.

Response 4: The Agency agrees with the commenter that initial MACT emission limits are to be based on the emissions of the best performing sources; however, the Agency disagrees with the commenter's assertion that the CAA section 112(d)(6) ongoing review and revisions involves recalculation of best performing sources. The EPA is not obligated to recalculate MACT floors in the course of the periodic technology review. *NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008); *Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 7–9 (D.C. Cir. 2015). Rather, CAA section 112(d)(6) requires review of technological advances in source operation and controls, coupled with revision of emission limits if warranted. The rule's use of PM CEMS as the compliance determination method for the fPM emission limit will not impair or impede review of future improvements to EGU process operation or non-Hg metals or fPM control devices, so the Agency finds the commenter's concerns unfounded.

Comment 5: Commenters stated that HAP metals have wide ranging health and environmental impacts and unless each is monitored directly and continuously, these impacts cannot be fully assessed. They said that simply monitoring PM provides only limited information for assessing these potential health and residual risk impacts. Direct measurement of each individual HAP metal should be required to fully assess environmental impacts and health risks related to such metals. They commenters said that current scientific literature is beginning to indicate that PM mass concentration may not be the best indice for associating health effects with exposure to ambient PM. Contemporary researchers in the field of airborne metals' health effects are finding that the metals components of PM are responsible for a substantial portion of the observed PM impact, and can cause various significant health effects from pulmonary inflammation to increased heart rate variability to decreased immune response. They said that these effects are not only seen from chronic exposure, but also from short-term peaks in ambient air concentrations (Chen and Lippmann 2009) and data show that the metals in PM may be more dangerous than other PM components (Konkel 2009). The commenters stated that a study of PM2.5 in 2010 showed that metals were the important source for cellular oxidant generation and subsequent health effects (Maciejczyk 2010). In addition, transition metals, such as iron, vanadium, nickel, chromium, copper, and zinc, have been cited as most likely to be toxic on the basis of their ability to support electron exchange (Ghio 1996), and catalyze and generate reactive oxygen species (ROS) in biological tissues (Chen and Lippmann 2009). The commenters said that ROS, such as hydroxyl radicals (OH·), are thought to be involved in various forms of lung injury and are considered to be both genotoxic and carcinogenic (Knaapen et al. 2004). The commenters concluded that taking this information into consideration, monitoring stack emissions for only PM does not provide an adequate depiction of the potential for the components of that PM to cause negative health effects.

Commenters stated that legislation concerned with monitoring only PM mass concentrations fails to address the substantial differences in potential health effects linked to specific metal species and their independent variability (Moreno 2009). They said that a more effective approach would be to address the specific metals of concern independently, focusing control efforts on the most toxic species. The commenters said they recommend that the EPA at least promulgate specific language in its rules to allow alternative multi-metals monitoring to demonstrate compliance with EPA proposed alternative HAP metal emission limits.
(The commenters provided the following references:

- Chen and Lippmann, (Chi-Chen, Lung and Morton Lippmann). "Effects of Metals within Ambient Air Particulate Matter (PM) on Human Health." Inhalation Toxicology, 2009: 21: 1-31.
- Konkel, Lindsey. "Heavy Metal: Some Airborne Particles Pose More Dangers than Others." Environmental Health News, December 17, 2009)

Response 5: The Agency acknowledges the comments and references related to the health and environmental effects of HAP metals. As mentioned earlier, as allowed by the NESHAP general provisions, an owner or operator interested in using an alternative such as multi-metals CEMS to demonstrate compliance with the equivalent metals limits provided in the rule may request permission from the Administrator to use an alternative test method under the provisions of 40 CFR part 63.7(f).

6.3 Removing Use of PM CPMS for Compliance Determinations

Comment 1: Commenters stated the option to use PM CPMS for compliance under the current MATS rule should be retained as a way to mitigate the high testing costs associated with PM CEMS – especially under the more stringent proposed PM limit – while still provide a continuous indicator of performance. The commenters believe the limited use of PM CPMS is due to three reasons:

1. The original PM CPMS provisions set the operating limit at the value measured during the compliance test, which would have eliminated any margin of compliance and made demonstrating compliance capricious. This was not "fixed" in the 2016 technical corrections at which point many facilities had selected other compliance demonstration methods.
2. Other sources that might have used the PM CPMS provisions have found the LEE provisions more attractive since it has allowed them to reduce the associated testing to once every three years after showing their emissions were less than half the limit for three years.
3. Sources might otherwise be inclined to use a PM CPMS but find the requirement to set the operating limit at a point representing 75% of the underlying PM standard (*i.e.,* to give up 25% of their compliance margin) to be too onerous.

Commenters stated that PM CPMS should be retained, particularly if the EPA eliminates the quarterly and/or LEE testing options, because like PM CEMS it offers "increased transparency and accelerated identification of anomalous emissions," which EPA suggest are its reasons for proposing that all existing coal-fired sources should use PM CEMS. The commenters said that under the new reporting requirements that start in 2024, sources that use continuous monitoring systems, which would include both PM CEMS and PM CPMS instruments, will be required to report the 30-boiler operating day averages in their quarterly compliance reports as well as the results of annual PM performance test and associated PM CMPS operating limits needed to interpret the compliance status of the PM CPMS 30-boiler operating day averages.

Response 1: The Agency disagrees with the commenters' suggestion to keep PM CPMS based on their supposition for PM CPMS non-use. Rather than speculate on potential motives for non-use, the Agency prefers to look at actual use patterns – very few EGU owners or operators chose to use PM CPMS for compliance purposes. While PM CPMS provide data more continuously and more transparently than quarterly testing, they do not supply data in terms of the emission limit. Because the Agency strives for continuous determination of the pollutant, not a parameter, of concern, PM CPMS will be removed from the rule and replaced by PM CEMS. Moreover, results reported in terms of the emission limit (pounds per million Btus), as obtained by PM CEMS, will be more transparent than milliamps or other parameters provided by PM CPMS for third parties such as citizen groups to assess when reviewing compliance reports.

CHAPTER 7

7. What compliance dates are we proposing, and what is the rationale for the proposed compliance dates?

Comment 1: Commenters expressed support for the Agency's proposed compliance dates of up to three years after the effective date for affected sources to meet any new emission limits of the 2023 Proposal. Commenters also supported allowing sources three years to install PM CEMS, if required when the 2023 Proposal is finalized. Commenters communicated that EGUs that determine major control upgrades are needed to meet the revised standards must carefully evaluate numerous financial, technical, and regulatory variables before they can decide whether affected EGUs can meet the revised standards and remain viable. Commenters conveyed that the regulatory and economic analysis will require a significant effort to complete considering other laws and regulations that affect coal-fired EGUs. Commenters agreed three years is reasonable for control equipment installation or modifications and associated designing, planning, budgeting, and procurement that may be necessary to meet the standard as allowed under CAA section 112(i)(3)(A). However, commenters expressed concern over potential delays due to the limited number of specialized vendors/companies with the expertise to conduct such work, and the current shortage on the availability of parts. Commenters recognized many of the parts are no longer in production and would have to be custom manufactured, which would add to the timeframe needed for compliance. Commenters expressed concern that the permitting process alone may take more than six months, and if there are public comments, public meetings, or contested case hearing requests, issuance of the pre-construction permit authorization may require several years to resolve all issues. Commenters also indicated that additional time is necessary to effectively operate emission control and monitoring equipment to demonstrate compliance with the revised standards. Some commenters suggested it would be more appropriate to allow time for any major modifications to be completed during the typical EGU three-year outage cycles to minimize costs and impacts to grid operations. Commenters agreed that the three-year allowance is consistent with the time the EPA allowed sources to comply when the 2012 MATS Final Rule was promulgated and is necessary to allow affected EGUs to evaluate whether additional controls will be required to meet the revised standards. Commenters concluded the proposed three-year timeline reasonably accounts for both the complicated process of converting to a new monitoring system and the forthcoming retirement of EGUs.

Commenters stated that the EPA must provide sufficient time to perform upgrade projects. They said the time frames for fPM improvements in the 2023 Proposal cannot be met. The commenters said that the EPA sets a three-year deadline from the forthcoming final rule's effective date to comply with the new MATS emissions limitations. Commenters advocated for additional time to allow for fPM emissions limitation compliance commensurate with the time frames in the S&L Young Analysis.

Commenters recommended the EPA apply an effective date of five (5) years to this regulation that allows for EGU's time to adequately budget, procure, install, and certify the necessary equipment and controls to comply.

Commenters noted that FF are the most expensive and complex technology likely to be utilized to control HAP emissions to comply with the 2023 Proposal, and it is reasonable to expect an FF to be deployed in two or three years. Commenters agreed with the 2023 ATP Assessment, that PM CEMS and HCl CEMS should only take a matter of months to deploy. Commenters stated for other fPM control options, upgrades to existing FF can be accomplished in less than a year and upgrades to ESPs may also be completed in under a year, with the most complex ESP upgrades taking up to two years. Commenters stated for Hg controls, fuel or scrubber chemical additive systems can be deployed in less than a year. Commenters suggested for units that need to make operational changes only, such as units with existing ACI systems that will need to increase treatment rates, a one-year compliance deadline is more appropriate. Commenters stated that in regard to PM CEMS, two years is an appropriate compliance deadline given that two-thirds of units currently do not have such systems in place and the demand for such systems may create manufacturing and installation delays; followed by testing to demonstrate initial compliance. Commenters noted that it is possible that some EGUs may not be able to complete all aspects of this transition to PM CEMS in time. Commenters felt that EGUs should be able to deploy and upgrade all controls in two years, and therefore two years with the possibility of a third year, if necessary, would be an appropriate timeline for compliance with the revised standards. (2023 ATP Assessment at 49)

Commenters supported the option of affected sources requesting a one-year extension for compliance, if the affected sources demonstrated it is necessary, similar to what was provided during the 2012 MATS Final Rule as allowed under CAA section 112(i)(3). Commenters expressed concerns about their ability to complete these projects in the current three-year compliance window because of ongoing supply chain issues that could limit the availability of parts (many of which require custom fabrication) and contract resources that are qualified to execute the work scope, in addition to the cost considerations associated with ESP and FGD projects. Commenters expressed concern during implementation that many units may need an additional year to avoid unnecessary threats to the reliability of the electric grid as with the original 2012 MATS Final Rule if the EPA finalizes the 2023 Proposal. Commenters suggested the Agency provide guidance in the 2023 Proposal's final rule regarding extensions under CAA section 112(i)(3). Commenters requested that the EPA establish, streamline, and simplify the process of applying for the one-year extension under CAA section 112(i)(3).

Response 1: The EPA acknowledges and thanks the commenters for providing these comments. We have taken these comments and the referenced information into consideration when establishing the compliance schedule for the final emission standards. The rationale for final compliance timeline for the emission standards is discussed in section III.C of the preamble.

Comment 2: Commenters suggested that the EPA use its authority to create subcategories of affected facilities that elect to permanently retire by the compliance date as the Agency has taken in similar proposed rulemakings affecting coal- and oil-fired EGUs. Commenters stated the EPA should subcategorize those sources that have adopted enforceable retirement dates and not subject those sources to any final rule requirements. They indicated that the EPA is fully authorized to subcategorize these units under CAA section 112(d)(1). Commenters asked that the EPA consider other simultaneous rulemakings, such as the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel Power Plants, where the EPA has proposed to essentially retain the current standard applicable to EGUs that would elect to shut down by January 1, 2032. Commenters also referenced the retirement date of December 31, 2032, in the proposed Effluent Limitation Guidelines.

Commenters expressed that creating a subcategory for units facing near-term retirements that harmonizes the retirement dates with other rulemakings would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, deliberating whether to install controls and continue operation longer than planned to recoup investments in the controls. Commenters suggested that the EPA allow units with limited continued operation be allowed to continue to perform quarterly stack testing to demonstrate compliance with the fPM limitations. Commenters relayed that imposing different standards on these subcategories would continue the status-quo for these units until retirement. Commenters requested that the EPA's actions recognize that it would make no sense to require an EGU slated to retire in the near term to expend substantial resources on controls in the interim since these sources are very unlikely to find it viable to construct significant control upgrades for a revised standard that would become effective in mid-2027, a mere five years before the unit's permanent retirement. Commenters further noted if the EPA does not establish such a subcategory or take other action to ensure these units are not negatively impacted by the rulemaking, the retirement of some units could be accelerated due to the high costs of installing a PM CEMS and the need to rebuild or upgrade existing ESP or install FF to supplement existing ESPs. Commenters stated although this may be the EPA's preferred outcome, the EPA cannot ignore the need for a coordinated retirement of thermal generating capacity while new generation sources come online to avoid detrimental impacts to grid reliability.

Commenters suggested that if the EPA decides to proceed with revised standards in this 2023 Proposal, the Agency should create a subcategory for coal-fired EGUs that elect by the compliance date of the revised standards (*i.e.,* mid-2027) to retire the units by December 31, 2032 or January 1, 2032; if the EPA prefers to tie this 2023 Proposal to the proposed emission guidelines instead of the effluent limitation guidelines and maintain the current MATS standards for this subcategory. Commenters requested that the EPA coordinate the required retirement date for the 2023 Proposal with others rules so that all retirement dates align. Commenters reiterated that the EPA has multiple authorities with overlapping statutory timelines that affect commenters' plans regarding the orderly retirement of coal-based EGUs and their ability to continue the industry's clean energy transformation while providing the reliability and affordability that their customers demand. Commenters suggested EGUs that plan to retire by 2032 should have the opportunity to seek a waiver from PM CEMS installation altogether and continue quarterly stack testing during the remaining life of the unit. They also suggested that should a unit not retire by the specified date; it would be required to immediately cease operation or meet the standards of the rule. Commenters supported an EGUs failure to comply would then be a violation of the 2023 Proposal's final rule subject to enforcement.

Response 2: The EPA has responded to this comment in section IV.C of the preamble.

CHAPTER 8

8. Cost, Environmental, and Economic Impacts

8.1 What are the air quality impacts?

Comment 1: Commenters stated that per the EPA's own analysis, 91% of units could achieve compliance with the proposed PM limit with current controls and lowering the PM limit would not have a large impact on the sector. They said that this means that there would be little to no actual environmental benefit from lowering the limit, since many regulated sources are already operating at this rate. In other words, the proposed tighter limit does very little to reduce actual emissions. The commenters said that tightening the PM limit only unnecessarily increases compliance uncertainty for the regulated sources already operating under the intense scrutiny of the federal government and various non-governmental organizations opposed to coal.

Commenters stated that in addition to the lack of actual PM emission reductions, the EPA provides no quantitative rationale of the issues to be resolved by lowering the limit. The commenters said that the EPA must explain what PM, or non-Hg metal HAP, environmental issues are currently being caused by North Dakota's EGUs subject to the current limit and how a lower limit will resolve these issues.

Commenters stated that this is not the first time that the EPA has expressed the desire to lower emissions limits, simply for the sake of lowering emissions limits and without a direct measurable improvement to the environment, when a regulated source is already achieving a lower emission rate. Commenters referenced their previous comments on this issue and stated that this approach disincentivizes regulated sources from operating below their current allowable limits. If the EPA (or a state) gets in the habit of lower limits solely because a regulated source is already achieving a lower limit, the regulated sources may not continue to operate below allowable levels for other species. Commenters believed the 2023 Proposal will ultimately result in more real-world air pollution as regulated sources will inevitably operate closer to their allowable limits in fear of being saddled with unnecessarily strict compliance burdens simply for operating better than they are required to.

Response 1: The EPA addresses comments on the EPA's authority in Chapter 1 of this document. Additionally, the EPA does not believe that tightening the standards in this rulemaking creates disincentives to emitting below allowable limits in other rules. If facilities are emitting below allowable limits, these emissions levels must be operationally and/or economically more advantageous than operating strictly at the limit.

Comment 2: Commenters stated that it is arbitrary for the EPA to take credit for CO_2 decreases associated with the 2023 Proposal when the EPA is simultaneously rendering any such emissions irrelevant in its contemporaneously proposed GHG NSPS rulemaking requiring carbon capture on these very same sources. They argued that the Agency is required to account for other rulemaking actions it has proposed when evaluating a given proposed rulemaking and as such, the EPA cannot double count anticipated CO_2 emission reductions from this rulemaking when this rulemaking would not in fact cause such reductions, or at least not to the same magnitude, when the EPA's other related rulemakings for this same source category are accounted for.

Commenters stated that the EPA's estimated benefits related to decreased ozone emissions is flawed because it accounts for decreases in ozone exposures generally, without accounting for the fact that the EPA has in another contemporaneous rulemaking determined that Montana emission sources do not significantly contribute to any out of state ozone concentrations above the EPA's NAAQS for ozone, and thus any benefits related to reduced ozone related to Colstrip emissions cannot be assumed to occur outside Montana.

Commenters stated that although the EPA estimates that a vastly disproportionate majority of costs and emission reductions (*e.g.,* of PM) will be localized at Montana power plants, the EPA does not appear to limit its modeling of benefits from reduced PM emission exposures to populations actually within a scope that could be affected by such plants, or otherwise account for the localized nature of benefits from reduced emission exposures to populations near relevant facilities the EPA anticipates PM emission reductions to actually occur. Commenters argued that it would be arbitrary to account for health benefits nationwide from reduced exposures without first demonstrating that such populations are actually geographically capable of benefitting from any reduction in emissions from Colstrip and the other facilities from which the EPA anticipates the 2023 Proposal to force PM reductions.

Response 2: The EPA generally considers finalized, rather than proposed, rules in the baseline of its analyses. The emission reductions anticipated under this rule would be attributable to this rule. Where possible, the EPA will include the requirements of this rule in the baseline for future power sector rules. Section 3.2 of the final RIA describes the power sector modeling platform and lists the major regulations that are incorporated into the baseline for this action,

As to the dispersion of impact of changes in ozone concentrations, when quantifying the number and economic value of ozone-attributable premature deaths and illnesses, the EPA estimates the change in exposure by using the results of photochemical air quality modeling simulations performed for the continental U.S. Using these air quality surfaces, the EPA estimates the impact on populations located both proximate to the affected facility as well as those individuals living away from the facility. Consistent with the best available science, the EPA quantifies the benefits of reducing ozone concentrations using a no-threshold model; this accounts for the change in the risk of premature death and illness at exposures commonly experienced by U.S. populations, including concentrations at relatively low levels.

With respect to the comment about PM emissions and localized impacts, the EPA address comments on the EPA's authority in Chapter 1 of this document. The health benefits analysis presented in the RIAs for this action is performed pursuant to Executive Order 12866, as amended by Executive Order 14094. The RIAs for this action analyze the benefits (and costs) associated with the projected emissions reductions under this rule to inform the EPA and the public about these projected impacts. As emissions are projected to change in many parts of the country, as well as potentially disperse regionally, the analysis covers the contiguous U.S.

8.2 What are the cost impacts?

Comment 1: Commenters had concerns regarding the projections made in the IPM reference case entitled "Post-IRA 2022 Reference Case" (Post-IRA IPM) used in this Rule. Their comments also extend to the EPA's use of the reference case in other rulemakings. They said that while the EPA may make projections to assess compliance impacts, those projections must be reasonable and premised on a firm foundation.

Commenters stated that the Post-IRA IPM makes projections based on a number of tax credit provisions of the IRA, which address application of Carbon Capture and Storage (CCS) and other carbon mitigation options. These include: (i) New Clean Electricity Production Tax Credit (45Y); (ii) New Clean Electricity Investment Credit (48E); Manufacturing Production Credit (45X); CCS Credit (45Q); Nuclear Production Credit (45U); and Production of Clean Hydrogen (45V). The commenters said that the EPA assumes that these IRA provisions will substantially change the generation mix of the nationwide power sector by 2030. They said the Post-IRA 2022 Reference Case includes compliance with the EPA's suite of power sector rules.

Commenters stated that the EPA assumes that these new tax credits will have sweeping impacts on the power sector – particularly in the short-time frame of only 7 years for generation to be retired and replacement generation to be built. The commenters said that the EPA's model fundamentally assumes that the IRA and other power sector rules will cause retirement decisions and replacement capacity to be built – which is uncertain in itself – and then forecasts that these changes can feasibly occur by 2030. They argued that many variables would need to fall into place to achieve this improbable outcome.

Commenters stated that although the IRA presents cooperatives with helpful opportunities, the EPA should not rely on the IRA in its projections in a rulemaking until implementation has further matured. The commenters stated that NRECA's Technical Analysis revealed assumptions and data used in the Post-IRA IPM are wrong or unrealistic. The Post-IRA IPM's flaws are significant enough to result in a different rule outcome. Commenters asked the EPA to correct these errors.

Response 1: Sections 3.2 and 3.3 of the RIA for this final action details the EPA's Power Sector Modeling Platform 2023. IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous U.S. for the entire electric power system. The EPA has used IPM for almost three decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM.

The modeled "baseline" for any regulatory impact analysis is a business-as-usual scenario that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. EPA frequently updates the baseline modeling to reflect the latest available electricity demand forecasts from the U.S. EIA as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements. This modeling used as the baseline for this rule includes recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (the IRA).

EPA has an obligation to represent all existing statutes as accurately as possible in baseline analysis. While it is important to recognize the key areas of uncertainty discussed in section 3.6 of the RIA, they do not change the EPA's overall confidence in the projected impacts of the final rule as presented in the RIA.

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts.

Furthermore, the potential impacts of the IRA are widely expected to be substantial in scope. A recent report considered projections from 10 multi-sector models and 4 electric power sector models and found that the IRA spurs substantial CO_2 emission reductions from the electric power sector of 49 to 83% (median of 69%) below 2005 levels in 2030, and lowers economy-wide CO_2 emissions, which includes electricity generation and use, by 35 to 43% (median of 39%) below 2005 levels in 2030.

Comment 2: Commenters observed that the residual risk conclusions are directly relevant to the cost considerations. The costs of the substantial fPM and Hg control projects that would be required by the 2023 Proposal are informed by the benefits of those projects, which in the CAA section 112(f)(2) analysis, is the cost measured against the reduction in health risk and other benefits. The commenters said that these costs lack reasonable justification without a nexus to any health benefits from reductions of HAP. They said, in fact, the EPA's benefit-cost analysis in the RIA did not include any quantification health benefits from HAP reductions. The commenters said that the EPA must factor its CAA section 112(f)(2) findings into its technology cost analysis.

Response 2: In addition to the residual risk review, the CAA requires the EPA to conduct a technology review for major sources every eight years. EPA evaluates whether there have been developments in technologies or other air toxics emission reduction approaches since issuance of the initial MACT. This analysis includes, but is not limited to, evaluating whether technologies available at the time of the initial MACT have changed to more efficient, cost-effective methods warranting tighter standards. The EPA also addresses comments on the EPA's authority in Chapter 1 of this document.

As noted in the section I.A.2 of the preamble to the final rule, in selecting the final standards, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112.

Separately, pursuant to Executive Order 12866 and Executive Order 14904, the EPA prepared an analysis of the potential costs and benefits associated with this action, which is presented in the RIA. The analysis presented in the RIA does not inform the setting of the standards; rather, the RIAs for this action analyze the benefits and costs associated with the projected emissions reductions under this rule to inform the EPA and the public about these projected impacts.

8.3 What are the economic impacts?

Comment 1: Commenters stated that the preamble to the 2023 Proposal discusses the success of the MATS rule, which was promulgated in 2012. As the EPA notes, 2019 data show that affected EGUs have reduced their Hg emissions by 86%, acid gas HAP emissions by 96%, and non-Hg metal HAP emissions by 81% compared to pre-MATS levels. The commenters said that in the EPA's 2020 National Emission Inventory data, coal- and oil- fired EGUs contribute significantly less Hg emissions and make up only 11.6% of all Hg emissions from all reporting sources. The commenters said that similarly, coal- and oil-fired EGU non-Hg metal HAP emissions account for 11.5% of total non-Hg metal HAP from all reporting sources.

Commenters stated that more recent data show greater HAP reductions from EGUs. They said the EPA's Emission Reduction Progress Report shows that coal- and oil-fired EGU sources regulated under MATS emitted a combined 3 tpy of Hg in 2021, a 90% decrease of Hg from 29 tpy pre-MATS in 2010. The commenters said that non-Hg metal HAP from coal- and oil-fired EGU sources emitted 246 tpy in 2020, which is a 70% decrease from 854 tpy in 2011.

Commenters stated that while the most drastic reductions in Hg and non-Hg metal HAP occurred around the compliance deadline for MATS, mostly due to substantial investments by EGU owners to meet the MATS standards, EGU HAP emissions continue to decline further, absent any revisions to the MATS standards, due in large part to regulatory pressure (*i.e.,* other EGU regulations the EPA has and is promulgating) as well as economic pressures that are leading inexorably to increasing shutdowns of coal-fired EGUs. The commenters said that in 2011, before MATS was promulgated, electric utilities owned 332 coal-fired EGUs in the U.S. In 2021, there are now 169 coal-fired EGUs in the U.S., a reduction of over 50%. They said that according to the EPA, based only on current public announcements of EGU shutdowns, there will be accelerated retirements of over 50% of the remaining coal-fired EGUs in the U.S. by 2040. In truth, many more coal-fired EGUs are likely to retire well before 2040, even if public announcements to that effect have not been made. The commenters said that for these reasons, the EPA should not seek to revise the MATS standard as it proposes in the 2023 Proposal. Not only are EGU HAP continuing their steady and substantial decline regardless of whether the 2023 Proposal is finalized as proposed; as discussed below, the risk that EGU HAP emissions pose is minute, and the 2023 Proposal itself–if finalized–would result in substantial additional near term-shutdowns of coal-fired EGUs. They argued that this would further exacerbate the reliability concerns that power generators and regional transmission operators have been grappling with and warning about.

Commenters stated that tradeoffs are further exacerbated by the anticipated costs of other EPA proposed rules regulating the power sector such as EPA's proposed rule, "Supplemental Effluent Limitations Guidelines (ELG) and Standards for the Steam Electric Power Generating Point Source Category" (the "ELG proposed rule") and the proposed rules, "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" (the "CAA section 111 proposed rules"). The commenters said that both the ELG proposed rule and the CAA section 111 proposed rules include this concept by proposing the establishment of subcategories where new requirements vary by the date a unit will cease coal combustion. They said that the EPA should consider establishing a similar mechanism in this proposed rule as the rationale for this approach is uniform across these rulemakings-to incentivize sooner coal retirements and to avoid significant new capital investment in coal units that will retire.

Response 1: The Agency conducted a review of the 2020 Technology Review pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since the original MATS rule was promulgated. EPA's response to comments with respect to the revised fPM standard are presented in section IV.C of the preamble. EPA's response to comments with respect to the revised Hg limits are presented in section V.C of the preamble.

For the EPA's response to comments regarding reliability concerns, see section II.D of the preamble to the final action. For the EPA's response to comments suggesting the EPA consider retirement-based subcategories, see section II.B of the preamble.

Comment 2: Commenters stated that the nation is facing an energy reliability crisis. The commenters said that the North American Electric Reliability Corporation recognizes the unprecedented, rapid evolution of the electricity grid due to retirements of fossil generation and renewable generation coming on-line. North American Electric Reliability Corporation predicts electricity shortfalls in the MISO portion of the electricity grid. They said that S&P Global reports that: "Utilities in MISO are retiring fossil capacity in exchange for investments in renewable energy resources either contracted or added to their rate base; however, those exchanges are not happening fast enough to replace all the generation coming offline." (Bennet, 2023).

Commenters stated that despite air quality improvements and reliability fears, the EPA presses the power sector further in the 2023 Proposal. The commenters said that this spring, the EPA released additional power sector rules. They said these rules that impact electric cooperatives include:

- Supplemental Effluent Limitations Guidelines and Standards: EPA proposes costly effluent control technologies. EPA's public comment period recently ended for ELGs.
- Regional Haze: This program is in the midst of the second planning period, ending in 2028. Many states, including North Dakota, recently submitted or are in the process of finalizing their state implementation plans which involve emission reductions to fulfill state reasonable progress goals.
- PM 2.5 NAAQS: EPA's proposal to lower the PM 2.5 annual standard further complicates the reliability equation. EPA is considering public comments in response to its proposed rule on the reconsideration of the NAAQS for PM. A lower PM 2.5 annual standard would restrict options for siting new electricity generation, particularly in urban

areas that have a higher background PM 2.5 value due to anthropogenic sources. That final rulemaking is scheduled for release later this year.

Commenters stated that the EPA should also consider the impact of the Federal Good Neighbor Plan for the 2015 Ozone NAAQS, the proposed GHG Standards and Guidelines for Fossil Fuel-Power Plants, and the proposed Effluent Limitation Guidelines rulemaking on the reliability of the nation's electric power grid.

Commenters stated that the EPA's suite of new rules further place reliability at risk. Department of Energy Secretary Granholm and EPA Administrator Regan signed a Memorandum of Understanding on electric sector resource adequacy and reliability coordination in March of 2023. The commenters said that this agreement memorialized their shared objective of supporting the continued delivery of "a high standard of reliable electric service." They said the compound effect of the EPA's proposed rules jeopardizes this objective by unreasonably affecting crucial baseload coal and natural gas power plants.

Commenters stated that the 2023 Proposal has a meaningful role among these rules, as it proposes costly retrofits and other requirements that are drivers for retirements without health or economic justification. The commenters said that the collective impact on reliability of the suite of regulations for coal and natural gas power plants must be evaluated by the EPA, Department of Energy, regional transmission organizations, affected EGUs, and others.

Commenters stated that in May, Jim Matheson, CEO of the National Rural Electric Cooperative Association, released the following statement on the reliability and cost impacts to the country's 900 electric cooperatives in the context of the newest addition to the EPA's suite of environmental compliance rules:

> "Nine states experienced rolling blackouts last December as the demand for electricity exceeded the available supply. Those situations will become even more frequent if EPA continues to craft rules without any apparent consideration of impacts on electric grid reliability. American families and businesses rightfully expect the lights to stay on at a price they can afford. The EPA needs to recognize the impact this proposal will have on the future of reliable energy before it's too late."

Commenters stated that the reliability and the costs of this 2023 Proposal should be considered as required by CAA section 112. The commenters said that it is crucial for the EPA to evaluate the overall regulatory context as the burden of environmental compliance on electric cooperatives and their end users is cumulatively affected by the compliance timelines of these concurrent rulemakings.

Commenters stated that the EPA does not give adequate consideration of the cost impacts of the Proposed Rule on cooperatives. They said that cooperatives have limited financial resources and assets to leverage. The commenters said that if cooperatives are unable to finance ESP upgrade projects within the time frames identified by the 2023 Proposal, the only choice is to shut down. They argued that the loss of power to North Dakota's rural communities is an unacceptable option. The commenters said the EPA should consider the specialized impacts on smaller utilities, which the Agency has done in other RTR reviews.

Commenters stated that last year, the EPA rejected other technologies based on cost per ton. They said for example, in the Proposed Rule for Bulk Gasoline Terminal NESHAP, the EPA found: "The cost-effectiveness and incremental cost effectiveness of reducing the area source emission limit for large bulk gasoline terminals to 10 mg/L are approximately $12,000 and $13,000 per ton of HAP emissions reduced, respectively, which we determined is not cost-effective." The commenters said that in comparison, even EPA's cost per ton estimates for the 2023 Proposal are far above this level (starting at $37,300).

Commenters requested that the EPA adopt a comprehensive "reliability safety valve" (RSV) that would allow grid operators to rely upon the EGUs subject to the EPA emissions restrictions, including restrictions imposed by the MATS rule, when necessary to serve system demand in the unusual event of an actual or anticipated grid emergency. They said that the EPA has previously approved an RSV in the context of the Clean Power Plan. Commenters believed a similar measure that applies more broadly across all EPA-regulated emissions would be appropriate because there are multiple EPA requirements that restrict operations of coal- and gas-fired units limiting the availability of those plants to the grid.

Commenters stated that if the EPA decides to proceed with a final rule consistent with the 2023 Proposal, the Agency should provide an accommodation or subcategory applicable to EGUs featuring a low capacity factor—as it does in the proposed GHG rule and the currently existing low utilization subcategory of the ELG Rule.

Commenters requested that the EPA consider adding additional language allowing for an administrative compliance order so the EPA may consider the reliability impacts of the proposed MATS rule on a case-by-case basis similar to the option for an administrative compliance order in EPA's recently proposed GHG rule.

Response 2: For the EPA's response to comments regarding reliability concerns, see section II.D of the preamble. With respect to comments about the cost-effectiveness estimates, see the EPA's response to related comments in section IV.C. of the preamble. With respect to the suggestion to establish subcategories like those in other rules, see the EPA's response to similar comments section II.B of the preamble.

With respect to comments suggestion the EPA consider the specialized impacts on smaller utilities, pursuant to the Regulatory Flexibility Act, the EPA performed an analysis of the cost impacts to small entities and found there is not a Significant Economic Impact on a Substantial Number of Small Entities. These analyses are found in section 5.2 of the RIAs for the proposed and final rules. The results of the small entity analysis for the final rule are also summarized in section IX.C of the preamble.

Comment 3: Commenters stated that in a February 24, 2023, the PJM regional transmission organization (RTO) that coordinates generation and delivery in a 13-state region, issued a review of its generation resource adequacy. They said that PJM declared the rush to retire traditional baseload generation resources “present[s] increasing reliability risks…" and "the amount of generation retirements appears to be more certain than the timely arrival of replacement generation." The commenters said, as detailed in the report, 40 GWs of baseload "thermal" generation sources (mostly coal fired assets) are projected to be retired by 2030, representing 21% of the ISO's installed capacity.

Commenters stated that the same analysis confirmed the challenges of replacing current coal fired generation with other resources, noting that 5.2 MW of solar capacity and 14 MW of wind generation capacity are needed to equal one MW of thermal generation. They said that as if the staggering replacement ratios were not enough- roughly 6,760 MW of solar or 18,200 MW of wind to replace a 1,300 MW coal plant- PJM's review revealed that few of these intermittent resource projects are actually complete: "Despite the sizeable nameplate capacity of renewables in the interconnection queue, the historical rate of completion for renewable projects has been approximately 5%."

Commenters stated that PJM also identified difficulties with replacing coal plants with natural gas generation and said that as PJM correctly observes, international demand for natural gas has strained fuel supplies "resulting in significantly higher fuel costs for PJM's natural gas fleet." They said, for example, from January 2021 to December of last year, the average cost of natural gas for electric generation increased 187%, from \$3.20 /MMBtu to \$9.20/MMBtu. The commenters stated that during certain months, the price of natural topped \$16.00 /MMBtu, a 400% increase over the January 2021 prices. From 2021 to 2022, to average price of natural gas to generate electricity in the U.S. increased 39.5% (+\$2.06). The commenters stated that the cost of coal to generate electricity increased as well, but only by 26% (+\$0.55) from January 2021 to December 2022. The average cost of all coal generation in the U.S. increased only 20% (+\$0.40) from 2021 to 2022. In West Virginia, the cost of natural gas to generate electricity increased +\$2.59/ MMBtu or 62% from 2021 to 2022 compared to coal generation costs that increased +\$0.35 or 16% during the same period. The commenters stated that, put simply, the PJM system footprint is running out of sources to provide reliable power during normal operating conditions, much less extreme weather events that test dependability of generation during periods of high demand. The commenters stated that in the referenced report, PJM predicts annual demand growth of 1.4% per year for the next 10 years, with certain areas of its system subject to growth as high as 7% annually. The commenters stated that coupled with accelerated coal plant retirements, higher cost natural gas and the reality of 8 intermittent wind and solar resources, the ISO accurately concludes “For the first time in recent history, PJM could face decreasing reserve margins” and “the amount of generation retirements appears to be more certain than the timely arrival of replacement resources.” As stated by PJM's CEO, “I think we need to subtract [generation resources] slower and subtract generation only when the replacement generation is here at scale.”

Commenters stated that in November 2022, NERC issued its Winter Reliability Assessment for 2022-2023, finding that “A large portion of the North American bulk power system is at risk of insufficient electricity supplies during winter peak conditions” and urging policy makers “to preserve critical generation resources”. The commenters stated that similar conclusions were issued by NERC in its 2022 Summer Reliability Assessment, finding that certain areas are facing capacity generation deficits “resulting in high risk of energy emergencies”. The commenters stated that these concerns were confirmed and echoed by the Federal Energy Regulatory Commission (FERC): "We're headed for a reliability crisis and we are just not ready yet to transition the nation's energy system to intermittent sources".

Commenters stated that in March of this year, NERC again alerted the EPA about the dangers of accelerating coal plant retirements through its various rulemaking initiatives, noting "a steady increase in reliability risk associated with the pace at which the transformation of the grid is occurring" and warning the EPA and the federal Department of Energy that "the pace of change needs to be managed and we have stressed the critical need to evaluate the impacts of these policies on reliability."

Commenters stated that recently, members of FERC detailed the tenuous status of the nation's electricity system to Congress, emphatically declaring "the United States is heading for a reliability crisis. I do not use the term 'crisis~ for melodrama, but because it is an accurate description of what we are facing:

> "I think anyone would regard an increasing threat of systemwide, extensive power outages as a crisis .... In summary, the core problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the addition of intermittent resources, primarily wind and solar, but the far too rapid subtraction of dispatchable resources, especially coal and gas. We know that there is a looming resource adequacy crisis. Our market operators have been explicitly telling us as much for years. Both MISO and ISO-NE have warned about upcoming scarcity and PJM, the Nation's largest wholesale market, and the one that serves Washington, D.C., has recently raised the alarm about impending shortfalls. Were any more proof required of our markets' failure, in the midst of PJM's dire warnings, somehow the prices in its procurement auction, at a time of impending scarcity, went down."

Commenters stated that commissioner James Danly also testified "As an engineering matter, there is no substitute for reliable, dispatchable generation. Intermittent renewable resources like wind and solar are simply incapable of, by themselves, of ensuring the stability of the bulk electric system." The commenters stated that in response to questions from the Senate Energy & Natural Resources Committee, Commission Chairman Phillip confirmed the testimony offered by the other FERC commissioners: "I am extremely concerned about the pace of retirements we are seeing of generators which are needed for reliability on our system. NERC and the grid operators have warned us about this. We might be fuel neutral, but we are not reliability neutral."

Commenters stated that unfortunately, the frailty of nation's electric system, which has been wrought with massive retirements of coal generation capacity, was clearly demonstrated during Winter Storm Elliot. The commenters stated that several ISOs, including the Tennessee Valley Authority and Duke Energy (in its Carolina system footprint) were forced to implement rolling blackouts to maintain the integrity of their power systems and in a least one case, to maintain minimum system voltage requirements for the Eastern lnterconnection. The commenters stated that both systems have retired substantial amounts of coal fired generation over the last 10 years and in the PJM footprint, the ISO took what can only be described as extreme measures to escape rolling blackouts or a broader systemwide failure. The commenters stated that the grid operator issued multiple conservation orders to virtually all the utilities in its system and availed itself of emergency provisions under the federal Power Act to allow restricted generation assets to produce electricity.

Commenters stated that in addition to the overall weakness of the nation's electric generation and delivery system, Winter Storm Elliot revealed an alarming infirmity in PJM's generation ability that has become dominated by natural gas generation. They said that during the storm, roughly 40% of the natural gas generation capacity was in “forced outage” unable to generate electricity or respond to increased calls for power to meet load. The commenters stated that an additional 6,000 MW of generation was expected and “scheduled” to generate on the morning of the storm but could not provide power. As noted by PJM itself, “the vast majority of these resources were gas fired...” The commenters stated that in a more recent review, PJM determined that the bulk of the gas plant outages were related to fuel supplies, with 473,208 MWh of generation capacity unavailable to produce power because of a lack of fuel. The commenters stated that while other generation sources experienced difficulties as well, including coal, those outages were mechanical, and equipment based. They said that plant components can be repaired, and generation can resume. They said that lack of fuel, especially one like natural gas that is supplied in real time, or “just in time” with no stockpiles on hand cannot be remedied: “Natural gas production in the Appalachian basin dropped by over 25% during the storm ... as a result, natural gas generation was limited in PJM and the Northeast... despite many plants having firm or uninterruptible natural gas supply contracts.”

Commenters stated that similar disruptions to gas fired generation were seen in other ISO/ RTO systems around the country, further revealing the brittle state of a power system that has become overly dependent on natural gas supplies. For example, in the MISO ISO, 75% of the system's forced outages were natural gas plants, with approximately 29% of the total gas generation fleet unable to produce electricity: “Gas supply availability contributed to increased unplanned outages ... that pushed MISO into emergency procedures.” Commenters stated that in addition to gas plant outages from fuel supply issues, other sources provided little generation to satisfy the increased demand. The commenters stated that wind generation increased at certain times but was very variable during the same period, with MISO noting that “wind was often derated over the time period” presumably due to “overspeed conditions” that prevent turbines from generating during high-wind speeds. The commenters stated that regarding solar generation, as observed by Duke Energy officials in proceedings before the North Carolina Utilities Commission, solar performed as expected but did not provide any power or increased generation when it was needed the most confirming their “intermittent” nature and inability to “load follow”. Commenters stated that in large part, it was coal fired generation that spared PJM and other ISOs from imposing rolling blackouts and more serious system failures. The commenters stated that coal and oil-fired power plants (with onsite fuel inventory) accounted for 80% of the increased generation capacity needed in PJM during the storm.

Response 3: For the EPA’s response to comments regarding reliability concerns, see section II.D of the preamble to the final action. Also note that, as shown in section 3.5.4 of the RIA for the final rule, the EPA does not project incremental changes in operational capacity to occur in response to the final rule.

Comment 4: Commenters stated that the EPA should reject what they called the self-serving opposition to the proposed MATS revision from Colstrip owners Talen Montana and NorthWestern Energy (and allied industry parties). In their early comments on the 2023 Proposal, Talen Montana and NorthWestern Energy urged the EPA not to finalize the proposed rule because the compliance costs for Colstrip Units 3 & 4—which failed to install modern PM control technology in response to the 2012 MATS—would cause the units to prematurely shut down. They indicated this would be detrimental to Montana's economy and grid reliability if the owners were to retire those units. They asserted that such claims deserve no weight.

Commenters stated that not only would it be improper to defer a national standard based on its impacts to the single regulated facility that avoided prior control upgrades, but also the Colstrip owners' claims related to impacts to Montana's economy and grid-reliability are not credible. The commenters said that as an initial matter, there would be nothing premature about near-term retirement of Colstrip. As noted, Colstrip Units 3 and 4 became operational in 1984 and 1986 and are approaching 40 years old. The fact that they cannot reliably comply with current air pollution standards suggests that the units already have reached the end of their economic useful life. They said that rather than continuing to resist investments that would improve the health of communities surrounding the Colstrip plant, Talen Montana and NorthWestern Energy, should plan for the transition away from coal energy and the closure of Colstrip. The commenters said that alternative energy sources—sources that lack the serious health consequences posed by continued coal combustion without proper pollution controls—are available and cost-effective.

Commenters stated that Talen Montana and NorthWestern Energy are outliers even among their Colstrip-owner peers, who already are committed to eliminating Colstrip power from their portfolios. The commenters said that Puget Sound Energy and Avista Corporation plan to exit their ownership by December 31, 2025. Portland General Electric and PacifiCorp will end their Colstrip ownership no later than the end of 2030. They asserted that only NorthWestern Energy and Talen Montana lack definitive plans to end their reliance on Colstrip by the end of the decade.

Commenters stated that as the last holdout among its regulated utility peers, NorthWestern Energy has not planned for alternative generation. In its biennial resource planning, NorthWestern did not consider future resource portfolios that exclude Colstrip, including scenarios in which dispatch planning models may find retirement of Colstrip the economically optimal option. The commenters said that NorthWestern's cost analyses and dispatch modeling have not considered the costs of reasonably foreseeable future regulation, such as control upgrade costs under the CAA's regional haze program, nor has NorthWestern put Colstrip to the test against other feasible generation alternatives, such as market purchases or the development of new renewable energy resources. The commenters said that NorthWestern does not appear genuinely interested in whether Colstrip is a good deal for its customers or not. They said instead, the company appears to cling to Colstrip as a prime revenue source for the company, and now NorthWestern has plans to increase its ownership in the plant—from 222 MW to 444 MW starting January 1, 2026. The commenters said argued that NorthWestern's financial incentive to keep Colstrip open is an illegitimate reason to avoid the establishment and enforcement of important health-based pollution limits.

Commenters stated that despite NorthWestern's claims about Montana's economy and grid reliability, NorthWestern Energy can replace Colstrip power with existing and alternative capacity, including from market purchases and abundant wind, solar, and storage resource opportunities. The commenters said that NorthWestern recently joined the Western Resource Adequacy Program, which has moved the company from a capacity deficit to a large capacity surplus. Commenters provided a table illustrating that NorthWestern's current capacity position improved by 101 MW in the winter and 180 MW in the summer relative to last year's projection. The commenters said that this was primarily driven by reductions in NorthWestern Energy's required planning reserve margin and increases in the capacity accreditation of reservoir hydro, wind, and solar under the Western Resource Adequacy Program. The commenters said that the Western Resource Adequacy Program provides these benefits by tapping diversity in load and resource output patterns across the region. They said that while the capacity projection in Table 1 includes NorthWestern Energy's 222 MW Colstrip share, it shows that NorthWestern Energy's capacity need is not nearly as dire as the company has claimed.

Commenters stated that even if NorthWestern Energy needs additional capacity, other resources such as wind, solar, and storage (made even more affordable under new Inflation Reduction Act programs), as well as market purchases, can work together to more cost-effectively and reliably meet that need than continued reliance on Colstrip coal power. NorthWestern's interconnection queue includes significant new generation, including new renewable and storage projects with signed interconnection agreements, the last step before a project proceeds to construction. The commenters said that beyond these resources, Montana is likely to see continued development of renewable and storage resources due to its strong renewable resources and the extended and expanded renewable and storage tax credit provisions in the Inflation Reduction Act.

Commenters stated that the Pacific Northwest region, in which NorthWestern Energy is a market participant, also has a large capacity surplus that will only grow as the Western Resource Adequacy Program comes into effect, so if NorthWestern needs capacity it can more cost-effectively obtain it through long-term market purchases. The commenters said that NERC's recently released Long-Term Reliability Assessment shows large capacity surpluses in the Northwest region through the end of this decade, as more than 9,000 MW of likely resource additions and an additional 5,000+ MW of potential resource additions keep pace with expected load growth and retirements. The commenters said that NERC's Winter Reliability Assessment also shows the Western Power Pool has a nearly 35% reserve margin for this winter.

Commenters stated that not only is abundant clean-energy capacity available to replace Colstrip power, but it would also provide significant reliability and economic benefits, rather than harm, to Montana. In a recent Montana district court trial, *Held, et al v. State of Montana*, Dr. Mark Jacobson, Ph.D., Director of the Atmosphere/Energy Program at Stanford University, provided expert testimony regarding "…the feasibility of transitioning the State of Montana to 100% clean, renewable energy in all energy sectors by mid-century." (*Held et. al. v. State of Montana*, Mont. 1st Jud. Dist. Ct, Lewis and Clark County, *Case No.CDV-2020-307.*) A key portion of his research was "to analyze resulting electric grid stability for the Western Electricity Coordinating Council region of the United States, which is the grid region in which Montana resides." The commenters said that Dr. Jacobson and his colleagues concluded that transitioning to 100% clean energy resources would reduce end use power demand by approximately 61.4%, would result in a stable grid, and would provide profound benefits for the state:

> "[C]onverting from fossil fuel energy to WWS [wind, water and solar] is estimated to eliminate ~130 Montana air pollution premature mortalities and many more illnesses per year in 2050, avoiding ~$1.7 billion per year (2020 dollars) in 2050 health costs (based on statistical cost of life, morbidity, and additional environmental impacts). Converting will eliminate another $21 billion in 2050 climate costs to Montana and the world. Most noticeable to those in Montana, converting to WWS will reduce annual total energy costs for Montanans from $9.1 to $2.8 billion per year, or by $6.3 billion per year (69.6 percent savings). The total energy, health, plus climate cost savings, therefore, will be a combined $29 billion per year (decreasing from $32 to $2.8 billion per year), or by 91 percent. This is called the social cost savings (or economic savings)." (*Id.*)

Commenters stated that replacement generation for Colstrip is available, and it is preferable to continued reliance on an uneconomic and polluting fossil fuel resource that has no place in the future energy economy.

Response 4: The Agency acknowledges these comments and addresses the rationale for the final fPM standards in section IV.D of the preamble.

Comment 5: Commenters stated that the EPA states in this concurrent proposed GHG NSPS rulemaking that CCS, and the additional control technologies required for CCS to work, may both cause co-reductions in fPM as well. The commenters said that accordingly, it is arbitrary for the EPA not to account for the impact of these planned fPM reductions on whether any additional controls on fPM were "necessary" for purposes of CAA section 112(d)(6) at all.

Commenters stated that the EPA's cost analysis does not appear to account for other indirect impacts of such temporary retrofit induced shutdowns, including unavailability of power during the retrofit, security risks associated with even temporarily reduced electric generation capacity, and increased costs to the utilities, coal suppliers, and ratepayers purchasing needed makeup power on the open market.

Response 5: The EPA considers the cost and emissions impacts of finalized rules in the baseline against which these incremental costs and benefits are measured. Furthermore, the EPA notes that while the pollution control retrofits that EGUs might install for compliance with this rule can require taking a unit out of service for some period of time when connecting ductwork, etc., these activities can normally be scheduled during otherwise planned outages that individually might last a couple of weeks to perhaps months for steam turbine overhauls. There are often multiple outages a year, and these are typically scheduled at times when load demand is low.

Comment 6: Commenters stated that if enacted, they also concerned that the 2023 Proposal might have unintended consequences on another important national policy objective - decarbonization and the transition to renewable energy. The commenters said that the Butte miners of the last century made copper that electrified the country and provided metals essential to the war efforts. They said that as a domestic producer of copper with an estimated 30 years of ore reserves, they are well positioned to supply copper - essential to renewable energy - to help meet the challenges of this century. The commenters said that this is not possible without reliable power.

Response 6: The EPA agrees that copper is an important domestic resource. For the EPA's response to comments regarding reliability concerns, see section II.D of the preamble to the final action.

8.4 What are the benefits?

Comment 1: Commenters stated that the EPA appropriately monetizes climate benefits using the social cost of carbon and specifically, the EPA relies on the interim estimates of the social cost of carbon from the Interagency Working Group on the Social Cost of Greenhouse Gases in the 2023 RIA.

Commenters stated that by adopting the Interagency Working Group's climate-damage estimate, the EPA properly adopts a global framework for valuing climate impacts, rejects a 7% discount rate, and makes other methodological choices based on the best-available and most widely-cited models for monetizing climate damages that existed at the time of the Interagency Working Group's analysis. The commenters said that however, in part because they do not include the most recent evidence, the Interagency Working Group's climate-damage valuations are widely considered to be conservative underestimates. They said that the EPA could additionally perform a sensitivity analysis to reflect the revised climate-damage valuations from the EPA's Draft SC-GHG Update which would indicate even larger climate benefits.

Response 1: As discussed in section VIII.E of the preamble and section 4.4 of the RIA, EPA has updated its approach and now uses estimates of the SC-GHG that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine[7]. The EPA published and used these estimates in the RIA for the December 2023 Final Oil and Gas NSPS/EG Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review."

Comment 2: Commenters stated that the EPA could enhance its discussion of the benefits of reducing HAP emissions in or alongside its tables comparing the monetized effects of the alternatives. The commenters said that the EPA's comparison tables for the costs and benefits of the regulatory options feature the monetized effects, and the EPA clarifies that "[t]he results presented in this section provide an incomplete overview of the effects of the proposal, because important categories of benefits, including benefits from reducing Hg and non-Hg metal HAP emissions, were not monetized and are therefore not directly reflected in the quantified benefit-cost comparisons." (2011 RIA at 7-7). The EPA "anticipate[s] that taking non-monetized effects into account would show the proposal to be more net beneficial than the tables . . . reflect." *Id.*

[7] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

Even if the EPA cannot monetize these benefits, the EPA could add a row quantifying HAP emission reductions to the table itself or a qualitative note about the HAP benefits to the table. The commenters said that additionally, in the accompanying discussion of HAP reduction benefits, the EPA focuses on the benefits of reducing Hg even though there are significant non-Hg metal reductions, too. They said the EPA could add further discussion of these benefits to this section to clarify their relevance.

Commenters stated that even if the EPA cannot monetize the benefits of HAP emission reductions, it is widely recognized that a cost-benefit analysis should give "due consideration to factors that defy quantification but are thought to be important" and that extends to factors that are not fully monetized. The commenters said that the mere fact that a benefit cannot currently be monetized says little about the magnitude of its value and in fact, some of the most substantial categories of monetized benefits of environmental regulation were once considered unquantifiable, let alone translatable into dollar terms. The commenters said that recognizing the potential significance of effects that cannot be fully monetized or quantified, executive orders governing RIA explicitly instruct agencies to consider such effects when analyzing proposed rules. The commenters said that similarly, Circular A-4 cautions agencies against ignoring the potential magnitude of direct unmonetized benefits, emphasizing that "the fact that benefits, costs, and transfers often are uncertain, or difficult to monetize or quantify, does not necessarily make them either highly speculative or minor." (OMB, Circular A-4: Draft for Public Review 28).

Commenters cited authorities described by the Court in *Michigan v. EPA* and said that the proposal's consideration of non-HAP health and climate benefits was consistent with the Court's recognition that the Agency's benefits analysis may not fail to consider important aspects of problems.

Commenters stated that the EPA should also qualitatively discuss the incremental benefits of non-Hg metal HAP emission reductions, since these emission reductions are a significant component of HAP emission reductions under the 2023 Proposal. The commenters said that lastly, even if the total benefits of each alternative are small, it is still possible that the benefits of one alternative are more highly concentrated in an overburdened community, which is relevant to assessing the distributional desirability of that alternative.

Commenters stated that in 2020, the Science Advisory Board (SAB) submitted an evaluation of the technical basis underlying EPA's 2020 MATS Residual Risk and Technology Review and Cost Review [Docket ID EPA-HQ-OAR-2018-0794-4572] The commenter said that evaluation specifically noted that the categorical exclusion of co-benefits in that analysis "depart[ed] the Agency's long-standing practice and is contrary to both the Agency's guidance document on economic analysis and to the recommendations of the Office of Management and Budget." They said it further noted that "[a]s the agency's guidance has been previously reviewed by the SAB, excluding co-benefits is a departure from the Board's recommended practice."

Response 2: The EPA expanded the discussion in the RIA of potential but not quantified impacts of HAP emissions reductions and the finalized monitoring provisions. There is additional text in the body of the RIA, as well as additional information presented in the benefit and net benefits tables in the RIA.

Comment 3: Commenters stated that nowhere in the record does the EPA quantify any benefit from reducing HAP from coal-fired EGUs beyond those achieved by the existing MATS regulations. The commenters said that if the residual risk from coal-fired EGUs HAP emissions is extremely small, there is hardly any benefit from reducing HAP further from these units. They said the EPA all but concedes those facts by claiming in the 2023 RIA only "co-benefits" derived from reductions in non-HAP that are not the target of section 112 of the CAA or this rulemaking.

Commenters stated that an example of the EPA' s suspect characterization of the health benefits is as follows: "While the screening analysis that the EPA completed suggests that exposures associated with Hg emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers." (2023 RIA at 0-8). The commenters said that the EPA admits that the current exposure associated with Hg is below levels of concern from a public health perspective, yet the EPA still advocates for further decreases. They said that if Hg exposure is not currently a problem, the EPA should not propose to further reduce the exposure. Commenters said they do not understand why the EPA wants to put further strain on North Dakota's critical energy grid; stress and potential failure of the grid would result in health and potentially life-threatening consequences.

Commenters stated that this theme is consistent across the entire "Benefits Analysis" section of the RIA and said another example is as follows:

> "Regarding the potential benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively .... Overall, the uncertainty associated with modeling potential benefits of Hg reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates-though importantly such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including methylmercury exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-Hg metal HAP were not expected to exceed acceptable levels, although we note that these emission reductions should result in decreased exposure to HAP for individuals living near these facilities." (2023 RIA at 4-1 – 4-2.)

Commenters stated that with respect to the EPA's claim that the 2023 Proposal will result in "climate co-benefits," commenters discouraged the EPA from utilizing the "social cost of carbon" metric to estimate any such benefits. The commenters said that metric remains subject to significant criticisms explained in greater detail in other contexts, such as whether it fairly recognizes the disconnect between local costs and global benefits, whether it overestimates the potential risks from climate change and therefore the benefits from reducing GHG emissions, and whether it is fair to assume similar emission reductions that would be needed globally to realize any benefits at all despite the lack of any framework for ensuring those global reductions will occur. Until those and other criticisms are address, commenters asked the EPA to refrain from relying on the “social cost of carbon” in evaluating the costs and benefits of any rule, but in particular the 2023 Proposal that is not intended to address climate change at all.

The commenters argued that the EPA’s reliance on the social cost of GHGs in unlawful and urged the Agency to refrain from relying on the interim SC-GHG estimates developed by the Interagency Working Group due to a number of flaws. The commenters stated that reliance on the SC-GHG suffers from these flaws:

- They said GHGs are not HAP and therefore not an appropriate target for a CAA section 112 rulemaking; further, GHG emissions from EGUs are not reduced by ESPs or FFs, and so the asserted benefits of the rule are wholly attenuated from what they require. Therefore, the SC-GHG estimates do not and cannot reflect a reasonably foreseeable effect of the proposed action.
- They said the lack of consensus on discount rates used for the SC-GHG estimates can lead to misleading results.
- They said the SC-GHG estimates have not been subject to a robust independent peer review and may not be considered a generally acceptable scientific method for evaluating effects of a proposed action under the CAA or APA.
- They said the SC-GHG estimates fail to comply with relevant administrative procedural requirements, including proper notice and comment procedures and agency guidance on peer review and information quality.

Commenters stated that the EPA analyzed the costs of additional controls by focusing primarily on industry-wide metrics, as if the costs of its proposal would be spread evenly over the entire industry. They said, however, the EPA’s basis for tightening the standards is that only a few units are under-performing, while the majority are over-performing, confirming costs of compliance with the new standard will not be evenly spread. The commenters said that according to the proposal, lowering fPM emission limits would bring a small number of sources, just 9% of the fleet, up to the performance of the rest of the fleet. Commenters stated that if the EPA were to evaluate the impact of the additional costs of its new standard on just on those sources that will incur the costs, the impacts would look more dramatic.

Commenters stated that the EPA should not seek to impose almost $2 billion of cost on any source category when there is no benefit associated with reducing the same pollutants the statute targets. The commenters said that the EPA certainly should not do so for an industry that is reducing its emissions at a high pace because it is on the way to retiring most, if not all, units in the source category in little over a decade. They said more importantly, as the Supreme Court admonished in *Michigan v. EPA*, the “[c]onsideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and disadvantages of agency decisions.” 576 U.S. 743, 753. They said that the Court faulted the EPA’s refusal to “consider whether the costs of its decision outweighed the benefits” (*Id*. at 750) in that rulemaking, explaining “[o]ne would not say that it is even rational … to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits.” *Id*. at 752.

Commenters stated that it is well-established that cost is a major consideration in technology review rulemaking. They said that under *Michigan*, therefore, the EPA must consider the costs of this regulation under section 112 of the CAA in relation to benefits intended by the statutory requirement mandating this regulation– HAP reductions. Moreover, this is the source category that was the subject of *Michigan*, and that may be regulated under CAA section 112 only upon a determination that it is "appropriate and necessary" to do so. The commenters said that since *Michigan* held that cost and benefits must be considered in determining whether it is "appropriate" to regulate EGUs under CAA section 112 in the first place, it necessarily follows that the same A&N threshold must also apply to this RTR rulemaking, which is merely a follow-on to the initial MACT rulemaking.

Response 3: In conducting the technology review under CAA section 112(d)(6), the D.C. Circuit established that the EPA is not required to consider health benefits in deciding whether to revise an emissions standard. In *Ass'n of Battery Recyclers v. EPA*, the Court stated that: "Equally without merit is industry petitioners' claim that EPA's decision to revise emissions standards under section 112(d)(6) was arbitrary and capricious. Although petitioners contend that EPA failed to consider public health objectives or other controls imposed on emissions sources in determining whether more stringent standards were 'necessary,' nothing in section 112(d)(6)'s text suggests that EPA must consider such factors. To the contrary, the statute directs EPA to 'tak[e] into account developments in practices, processes, and control technologies,' . . . not public health objectives or risk reduction achieved by additional controls." 716 F.3d 667, 672 (D.C. Cir. 2013) (citing 42 U.S.C. § 7412(d)(6)). As the EPA explained in the 2023 Proposal (88 FR 24865) and final rule the EPA does consider costs, technical feasibility, and other factors when evaluating whether it is necessary to revise emission standards under CAA section 112(d)(6), consistent with the statute's direction to "require the maximum degree of emissions reductions . . . achievable." CAA section 112(d)(2). And as discussed at length in section IV.C.1 of the final rule preamble, declining to require standards that meet the criteria under 112(d)(6) because the EPA had concluded the residual risk review would be inconsistent with the text, structure, and legislative history of section 112.

Moreover, it is not the EPA's practice (and the EPA does not think it is appropriate) to rely on the results of benefit-cost analyses undertaken to comply with E.O. 12866 in determining whether to revise a CAA section 112 standard. Most importantly, this is because important categories of benefits from reducing HAP cannot be monetized, making the monetized results of the benefit-cost analysis ill-suited to the EPA's decision-making on regulating HAP emissions under CAA section 112. As discussed in the 2023 Proposal (88 FR 24870) and final rule, the EPA considered costs in a variety of ways in determining the appropriateness of updating emissions standards pursuant to CAA section 112(d)(6). While there is some overlap in the consideration of costs for the revised standards the EPA is promulgating pursuant to its CAA section 112(d)(6) authority, and the EPA's analysis of the overall costs and benefits of the rule pursuant to E.O. 12866 (discussed in section VIII of final rule preamble), the EPA is not required to, and does not believe it is appropriate to, rely on the results of the monetized benefit-cost analysis in determining whether it is necessary to revise standards under CAA section 112(d)(6). Further, the EPA finds that its consideration of costs, in addition to other statutory factors, is consistent with the Supreme Court's direction in *Michigan v. EPA* that "[i]t will be up to the Agency to decide (as always, within the limits of reasonable interpretation) how to account for cost." 576 U.S. 743, 759 (2015). The EPA disagrees with the commenters insofar as they suggest that the EPA was required—under *Michigan* or any other authority—to rely on the results of the benefit-cost analysis in setting standards in this rulemaking. In *Michigan*, the Supreme Court concluded that the EPA erred when it concluded it could not consider costs when deciding as a threshold matter whether it is "appropriate and necessary" under CAA section 112(n)(1)(A) to regulate HAP from EGUs, despite the relevant statutory provision containing no specific reference to cost. 576 U.S. at 751. In doing so, the Court held that the EPA "must consider cost— including, most importantly, cost of compliance—before deciding whether regulation is appropriate and necessary" under CAA section 112. *Id.* at 759. In examining the language of CAA section 112(n)(1)(A), the Court concluded that the phrase "appropriate and necessary" was "capacious" and held that "[r]ead naturally in the present context, the phrase 'appropriate and necessary' requires at least some attention to cost." *Id.* at 752. This capaciousness was relevant in the context of section 112(n)(1)(A) because that section directs the EPA to determine "whether to regulate" the emission source, which is a context in which "[a]gencies have long treated cost as a centrally relevant factor." *Id.* at 753. The Supreme Court added in *Michigan* that it "need not and [does] not hold that the law unambiguously required the Agency, when making this preliminary estimate [of costs under the 'appropriate and necessary' standard of CAA 112(n)(a)(1)], to conduct a formal cost-benefit analysis in which each advantage and disadvantage is assigned a monetary value. It will be up to the Agency to decide (as always, within the limits of reasonable interpretation) how to account for cost." *Id.* at 759.

In this rule, the EPA has accounted for cost in multiple ways that satisfy the Court's admonition in *Michigan*. Further, given both the difficulty of monetizing the benefits of HAP reductions and the statutory requirement to reduce HAP emissions to the "maximum degree" achievable, the EPA does not believe that the results of a benefit-cost analysis are an appropriate metric to rely on in the context of setting the standard in this rule. Notably, the EPA is unable to monetize the benefits of the HAP reductions, which are the target pollutant in this rule.[8] In addition, the benefits of the additional transparency provided by the requirement to use PM CEMS for communities that live near sources of hazardous air pollutants, and the assurance PM CEMS provide that the standards are being met on a continuous basis, are not monetizable. While the EPA does not believe benefit-cost analysis is the right way to determine the appropriateness of a standard under CAA section 112, the EPA notes that when all of the costs and benefits of this action are taken into account (including non-monetized benefits) this final rule is a worthwhile exercise of the EPA's CAA section 112(d)(6) authority.

Regarding the discount rate used within the SC-GHG, consistent with the recent scientific literature, the recommendations of the National Academies, and the recent update of OMB Circular A-4, the SC-GHG now relies on the use of a dynamic discount rate. This discount rate is calibrated to observed market interest rate in the near term and uses a Ramsey approach to dynamically update the discount rate over the long-term. See the preamble of this rule, the 2023

[8] *See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding*, 88 FR 13956, 13970-73 (March 6, 2023) (discussing current limitations to monetizing and quantifying most benefits from HAP reductions).

Final Oil and Gas NSPS RIA, and the supplementary document for the Final Oil and Gas NSPS, "EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances," for more details. Within the RIA for this final rule, EPA uses updated SC-GHG estimates that EPA believes represents the latest available science and follows the recommendations of the National Academies of Science, Engineering, and Medicine. Please refer to the appendix to the rule, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances," for detailed responses pertaining to the rigor of the updated methodology, including the discounting approach.

Note that the EPA presented these updated discount rate estimates in a sensitivity analysis in the December 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, that was included as Supplementary Material to the Oil and Gas Supplemental Proposal RIA and explained the methodologies used for developing the new Social Cost. The EPA published and used these estimates in the main analysis of the RIA for the December 2023 Final Oil and Gas NSPS/EG Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" and responded to public comments received on the new estimates in the Response to Comments document for the Final Oil and Gas Rulemaking.

EPA follows applicable guidance and best practices when conducting its benefit-cost analyses, including OMB Circular A-4 and EPA's Guidelines for Preparing Economic Analyses. We therefore consider our analysis methodologically rigorous and a best estimate of the projected benefits and costs associated with the final rule.

With respect to the social cost of greenhouse gases (SC-GHG), as more fully discussed in and RIA Chapter 4.4, EPA has updated its approach in the final rule and the final approach uses updated estimates of the SC-GHG that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[9] The EPA published and used these estimates in the RIA for the Final Oil and Gas NSPS/EG Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," signed December 2, 2023. As we explain in RIA Chapter 4.5, the SC-GHG is based on a voluminous record, significant public process, and peer-review by an expert panel. EPA's use of SC-GHG for purposes of assessing the climate benefits of this rulemaking is clearly reasonable.

An updated discussion of the reasons for focusing on the global impacts of GHGs when calculating the SC-GHG can be found in the preamble for this final rule, as well as the RIA for the December 2023 Final Oil and Gas NSPS/EG Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." Within the RIA for this final rule, EPA used updated

[9] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

SC-GHG estimates that EPA believes represents the latest available science and follows the recommendations of the National Academies of Science, Engineering, and Medicine. Please refer to the appendix to the RIA, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances" for detailed responses pertaining to the rigor of the updated methodology and responses pertaining to the global focus of the SC-GHG estimates.

Note that the EPA presented these updated estimates in a sensitivity analysis in the December 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, explaining the methodological updates that was included as Supplementary Material to the Oil and Gas Supplemental Proposal RIA. The EPA published and used these estimates in the main analysis of the RIA for the December 2023 Final Oil and Gas NSPS/EG Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" and responded to public comments received on the new estimates in the Response to Comments document for the Final Oil and Gas Rulemaking.

Contrary to assertions, EPA has fully complied with applicable requirements, including Section 307(d) of the Clean Air Act in this rulemaking. Contrary to these commenters assertion that EPA, and the federal government more generally, has no statutory authority for the use of the SC-GHG, the government in fact started using an SC-GHG value in response to a 2008 court ruling on a Department of Transportation fuel economy rule (see the 2023 Final Oil and Gas NSPS RIA for a more complete history of government use of the SC-GHG). The 2021 IWG values for the SC-GHG were set to be equal to the estimates developed by the IWG in 2016 prior to it being disbanded. These prior estimates were the product of a substantive process, and were approved by the 2017 NAS report as being reasonable to use as a temporary measure while developing an improved set of estimates.

With respect to the inclusion of the co-benefits of GHG reductions in EPA's analysis to which numerous commenters objected, it has been standard practice for decades to include co-benefits within benefit-cost analyses. Whether the rule is intended to reduce HAPs, PM precursors, GHGs, or any other pollutant is not relevant to the decision to include GHG reductions in the analysis. This is no different than the inclusion of ancillary costs within the analysis. Both the 2003 OMB Circular A-4 ("Identify the expected undesirable side-effects and ancillary benefits of the proposed regulatory action and the alternatives. These should be added to the direct benefits and costs as appropriate") and the updated 2023 OMB Circular A-4 ("Your analysis should look beyond the obvious benefits and costs of your regulation and consider any important additional benefits or costs, when feasible") encourage the inclusion of co-benefits and co-costs (or ancillary benefits and costs).

8.5 What analysis of environmental justice did we conduct? (Executive Order 12898)

Comment 1: Commenters state that HAP emissions from coal-fired power plants continue to disproportionately impact people of color and low-income communities in the Southeast. The commenters said that an assessment of the demographic data in the vicinity of three power plants—Plant Barry in Alabama, and Winyah Generating Station (Winyah) and Wateree Station (Wateree) in South Carolina—reveals that disproportionate numbers of people of color and people with low incomes live in the vicinity of all three plants compared to the overall demographics of the state in which the plants are located.

The commenters said that specifically, the population living within 10 kilometers of Plant Barry in Alabama consists of 47% people of color overall, and 39% Black people, compared to statewide percentages of 35% and 27%, respectively. They said within 5 kilometers of the plant, the disparities are even greater: the population comprises 53% people of color and 43% Black people. Likewise, the two plants in South Carolina are particularly striking examples of the disproportionate burdens that people of color and low-income communities face. They further said that the overall population of South Carolina is 37% people of color and 27% Black people, and the state poverty rate is 15%. But within 10 kilometers of the Winyah plant, the population is 54% people of color and 47% Black people, and the poverty rate is 21%. Moreover, within 1 kilometer of the Winyah plant, the percentages of people of color and of Black people jump to 69% and 68%, respectively. Finally, the population within 10 kilometers of the Wateree plant in South Carolina is 85% people of color and 82% Black people—more than double the statewide percentages of 37% and 27% — and the poverty rate is 23% while the state-wide poverty rate is 15%.

Commenters stated that the EPA should evaluate all relevant impacts at the level most appropriate to capture those impacts and tailor the demographic analysis appropriately to understand who is most impacted. This level can depend on the dispersal pattern and distance traveled by the pollutant at issue. The commenters said that the EPA should conduct demographic analysis at the appropriate level for the pollutants studied in order to best analyze impacts on the most-affected communities and accordingly, the EPA should explain why averaging population within a 10 km radius is the appropriate analysis for the pollutants covered by this rule.

Commenters stated that averaging the demographics of a large set of facilities could obscure significant demographic differences at individual facilities. The commenters said that by examining the demographic profiles of individual facilities to understand the communities potentially most heavily impacted by pollution, the EPA could determine if emission reductions at specific facilities would affect environmental justice communities of interest. The commenters said that the EPA could then evaluate how each statutorily permissible alternative affects emission reductions at facilities near these communities and better understand the alternatives' respective distributional impacts.

Response 1: For the proximity analysis, as indicated in section 6.4 of the final RIA, the 10-km distance was determined to be the shortest radius around these units that captured a large enough population to avoid excessive demographic uncertainty. Specifically, a 5-km radius was evaluated, but it was found that 12% of the units had fewer than 100 people living within 5km of the units. Therefore, a 10-km distance, which yielded only 3% of the units with a population of less than 100 people, was chosen to provide greater certainty in the demographics. Although we show the overall demographics in the RIA for the groups of units investigated, the analysis did include facility-level demographics data. This facility-level demographic data will be submitted to the rulemaking docket for the public to access.

Comment 2: Commenters stated that Congress expressed a clear intent to reduce the harms that HAP inflict on these often disadvantaged, overburdened communities through regulation under CAA section 112. The commenters said that these impacts on overburdened communities refute any hypothetical claims by opponents that it is not necessary to strengthen the standards, in light of multiple statutory indicia of Congress's concern with protecting the most exposed individuals and sensitive populations—which have been shown largely to overlap with environmental justice communities because of historical and ongoing discrimination and other chemical, environmental, physical, and social stressors and extrinsic vulnerabilities. The commenters said that because these considerations are important to the threshold decision whether to regulate—and conduct ongoing risk evaluations for—this source category, they would dispel any argument that the EPA's action to strengthen the standards under CAA section 112(d)(6) is unreasonable or unwarranted.

Commenters stated that under CAA section 112(d)(6), the EPA's review is a recurring regulatory requirement that Congress intended to achieve maximum feasible reductions in HAP emissions regardless of remaining risks. From a policy standpoint, that obligation is all the more important where HAP emissions are inflicting cumulative—though unquantifiable—harms on already overburdened communities, which are often communities of color or low-income communities. The commenters said that moreover, certain "developments," such as improvements in pollution monitors that could benefit fenceline communities, may enhance equitable outcomes under the standards. The commenters said that accordingly, the EPA's strengthening of the standards is important to address persistent impacts from EGUs' HAP emissions on environmental justice communities.

Commenters stated that benefits to communities of color, Indigenous communities, and low-income communities foreclose any arguments that a strengthening of the standards that reflects developments in pollution controls is not necessary. Executive Order 12898 directs each federal agency to "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." (Executive Order 12898, section 1-101, 59 FR 7629). The commenters said that it is appropriate for the EPA to address disproportionate impacts on communities of color, Indigenous communities, and low-income communities based on several statutory considerations as well.

Commenters stated that Congress required the EPA to set standards reflecting the maximum achievable emission reductions for hazardous air pollution because Congress understood the importance of protecting the public from this especially dangerous class of pollutants. Congress also required that special attention be given to reducing harm to "sensitive populations." The commenters said that based on the evidence showing the numerous severe health concerns implicated by HAP, commenters strongly support strengthening the MATS limits, which will protect the health of all Americans, but especially the sensitive populations impacted by EGU hazardous pollution who are disproportionately communities of color, Indigenous communities, and low-income communities.

Response 2: The EPA acknowledges the commenter's support in its decision to strengthen the standards. As exposure results generated as part of the 2020 Residual Risk analysis were below both the presumptive acceptable cancer risk threshold and the noncancer health benchmarks, and this final regulation should still reduce exposure to HAP, there are no 'disproportionate and adverse effects' of potential EJ concern. We also note that the potential reduction in Hg and non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended standards. The analysis supporting these conclusions is presented in section 6 of the final rule RIA. The analysis is also summarized in the preamble in the Executive Order 12898 section.

Comment 3: Commenters stated that the EPA's proposal to require strengthened fPM standards as a surrogate for non-Hg metals would reduce the pollution burden of communities of color, low-income communities, and Indigenous communities disproportionately impacted by the pollution emitted from the covered coal plants. The commenters said that because $PM_{2.5}$ contains toxic metals, strengthened fPM standards would reduce the toxic metals exposures disproportionately experienced by these communities. The commenters said that in addition, recent studies more closely link exposures to PM and ozone to a range of health impacts and risks, especially among communities facing multiple stressors and vulnerabilities, which are often communities of color, Indigenous communities, or low-income communities.

Commenters stated that in summarizing the benefits from $PM_{2.5}$ and ozone reductions achieved under MATS, the EPA has observed that "[n]ewer scientific studies strengthen our understanding of the link between $PM_{2.5}$ exposure to a variety of health problems, including: premature death, lung cancer, nonfatal heart attacks, new onset asthma, irregular heartbeat, aggravated asthma, decreased lung function, and respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing." (87 FR 7669). Commenters noted that the Agency, in the 2019 Integrated Science Assessment for Particulate Matter, also determined that there is a "likely to be causal relationship" between long-term $PM_{2.5}$ exposure and nervous system effects such as cognitive decrements and dementia. And the 2020 Integrated Science Assessment for Ozone finds a "likely to be causal relationship" between short-term ozone exposure and key metabolic effects such as disruptions in the body's processes to maintain stable levels of glucose and insulin.

Commenters stated that new research also indicates that $PM_{2.5}$ exposures from coal-fired power plants disproportionately harm Black populations. The commenters said that in 2011, the EPA concluded that MATS would significantly reduce the risks of $PM_{2.5}$-related premature mortality in the counties with the highest preexisting risk, but that those counties were correlated with low-income and low-education populations, rather than with any race. The commenters said that from 2010 to 2016, however, inequalities in exposure to $PM_{2.5}$ for people of color and low-income populations have increased even as overall levels have declined. The commenters said that while MATS may or may not have improved equality in exposures to $PM_{2.5}$, it is highly likely that the large reductions that it achieved have been critical to lessening the absolute harm of $PM_{2.5}$ exposures and therefore the severity of inequitable harms. They said this advantage to strengthening the standards for EGUs under CAA section 112 only underscores that revisions are necessary.

Commenters stated that it is important that—in addition to disproportionate impacts from coal-fired EGUs' HAP emissions viewed in isolation—cumulative metals emissions from various source types such as EGUs and mine waste dumps may disproportionately harm some populations, such as Native American tribes in the Southwest. The commenters said that the Navajo Nation has experienced high reported emissions of multiple metals and above-average exposures to multiple metals, including uranium, cadmium, lead, and arsenic, which may have partially resulted from mine wastes. The commenters said that further, zinc deficiencies may have an additive effect on oxidative stress and inflammation response, which calls for consideration of nutritional deficits among some groups when evaluating the impacts of EGU HAP emissions.

Commenters stated that the Southern Environmental Law Center, in comments submitted April 11, 2022, on the EPA's 2022 Proposal, included a technical analysis by Dr. Ranajit (Ron) Sahu. The commenters said that as set forth in Dr. Sahu's report, he, along with Dr. Andrew Grey, conducted air dispersion modeling of emissions, including PM_{10}, from Plant Barry and Winyah. PM_{10} is the non-Hg metal HAP surrogate for the generating units at both plants. The commenters said that this modeling revealed that "the maximum impacts from the plant's emissions were predicted to be around 5 km or less distant from the plant, with potential impacts on those living near the plants." *Id*. at 2. They said thus, perhaps not surprisingly, the individuals living closest to these plants are also the individuals most exposed to the emissions of non-Hg metal HAP.

Commenters stated that stricter standards under MATS certainly would reduce some of the impacts from non-Hg metal HAP on the individuals most exposed to emissions from Barry, Winyah, and Wateree. The commenters said that for these comments, Dr. Sahu assessed the expected reduction in emissions of non-Hg metal HAP from Plant Barry Unit 5, and from all units at Winyah and Wateree, using the surrogate of fPM with fPM emissions based on (1) the EPA's proposed limit of 0.010 lb/MMBtu; (2) the Agency's proposed alternative fPM limit of 0.006 lb/MMBtu; and (3) a stricter limit of 0.0024 lb/MMBtu discussed above. The commenters said that for example, with respect to Plant Barry Unit 5, for 2022, using the heat input reported for 2022, fPM emissions under the current limit of 0.030 lb/MMBtu could have been up to 1,120,308 lb, or approximately 560.15 tons. Under the proposed limit of 0.010 lb/MMBtu, fPM for 2022 would be limited to 373,436 lb, or about 186.72 tons. The commenters said that under the EPA's alternative limit of 0.006 lb/MMBtu, and assuming the same 2022 heat input, fPM for Unit 5 would be limited to 224,062 lb, or about 112.03 tons. The commenters said that finally, under a stricter limit of 0.0024 lb/MMBtu, discussed above, fPM emissions in 2022 would have been limited to 89,625 lb, or 44.81 tons. This represents more than a twelve-fold decrease in the limit for fPM emissions as compared to the present 0.030 lb/MMBtu standard.

Response 3: The EPA acknowledges the commenter's support in its decision to strengthen the standards. When quantifying air pollution-attributable effects, The EPA selects endpoints for which there exists a causal or likely to-be-causal relationship between the pollutant of interest and the effect. Next, the EPA identifies epidemiologic studies that report risk estimates appropriate to use when calculating the number of adverse events attributable to the pollutant of interest. Sufficient evidence existed to quantify certain neurological effects. The EPA's approach for selecting and quantifying endpoints may be found in *Technical Support Document:*

Estimating PM2.5- and Ozone-Attributable Health Effects (U.S. EPA, 2023). Additionally, the EPA does not have data and methods to consider the potential for nutritional deficits to have additive health impacts from EGU HAP exposure.

Comment 4: Commenters stated that certain low-income and minority populations may face greater exposures to methylmercury from local deposition of EGU emissions than others do. The commenters said that the refined modeling exercise discussed above produces results that may be examined through a demographic lens by considering that, in 2010, EGUs with large Hg emissions frequently were located near low-income and minority communities.

Commenters stated that Congress's special concern for these communities may be inferred from the requirement for the EPA to study the threshold for Hg concentrations in fish tissue that may be consumed by "sensitive populations" without adverse effects to public health. The commenters said that Congress does not define the term "sensitive populations," but it is reasonable to interpret the phrase to include populations who face exposures to one or more HAP that affect the same physiological functions, whether from EGUs or other source categories, as well as cumulative exposures to individual pollutants through different pathways. The commenters said that it is also reasonable to include populations who are overburdened by other air or water pollution, environmental or social stressors, and vulnerabilities such as nutrient deficiencies that could exacerbate the health harms of HAP exposures. They said there is no reason to believe that Congress meant sensitivity only from intrinsic vulnerabilities (*e.g.,* existing health conditions, genome), when many other stressors (*e.g.,* other chemical exposures, discrimination, poverty, poor housing quality) and extrinsic vulnerabilities (*e.g.,* low socioeconomic status, lack of access to health care) may also render a person more susceptible to exposures to a HAP.

Commenters stated that in addition to the methylmercury subpopulation risks based on information known to the EPA in 2011, as discussed above, new research highlights the heightened risks to Native American communities in particular. The commenters said that the EPA's proposed removal of the lignite loophole and tightening of the standards for lignite plants would reduce Hg emissions at these plants and yield substantial health benefits for the Native American communities that disproportionately live near lignite-burning coal plants.

Commenters stated that the EPA's extension of the 2011 Mercury Risk Assessment as part of the 2023 Final A&N Review provides additional evidence for the risks to Native American Tribes. The commenters said that the EPA observed in the 2022 risk assessment that the Agency's estimates for fish consumption among Native American Tribes may be too low or missing in some areas, and that these populations' fish-consumption rates may be similar to the rates observed for other populations in those areas, such as low-income White and Black people in the Southeast.

Commenters stated that a 2023 study conducted by Harvard researchers documenting the sociodemographic disparities in exposure to Hg from lignite-burning coal plants found possible heightened Native American exposures to methylmercury through fish consumption near some of the largest Hg-emitting power plants in the U.S., in North Dakota and South Dakota. The commenters said that the authors determined that individuals consuming self-caught fish may be exposed to levels of methylmercury exceeding the EPA reference dose. Regions containing the U.S. plants with the lowest reductions in Hg deposition from 2010 to 2020 overlap with higher-than-average high-frequency fish consumers, raising specific concern over elevated methylmercury exposures for Native American populations in the Dakotas who frequently consume seafood. The commenters said that in addition, the research reinforces prior findings that show a lack of distributional justice in power plant siting. Specifically, the "significantly greater proportions of low-income individuals" living within 5-km of active facilities in 2020, as compared to plants that retired since 2010, suggests that plant retirement decisions may be impacted by the relative wealth of the surrounding communities.

Commenters stated that the cumulative impacts of legacy Hg pollution, especially pronounced in urban settings, speak to the importance of reducing Hg pollution in order to correct inequality in health risk, which is disproportionately borne by marginalized communities. Urban rivers are often important food sources for lower-income urban populations; thus, urban anglers are at higher risk of exposure to contaminants via fish consumption, and Lawrence freshwaters like the Concord and Merrimack Rivers are affected by legacy Hg contamination (including from Superfund and Brownfield sites, in addition to the deposition from coal-fired EGU emissions) that persists in previously deposited and emitted pools. The commenters said that the cumulative effects of this Hg act as threat multipliers and put urban, under-resourced populations at risk for other health and environmental impacts, including exposure to other toxins.

Commenters stated that in addition, the EPA has observed that there may be benefits from regulating EGUs under CAA section 112 insofar as society places a premium on reductions of inequality in terms of health risks. This altruistic benefit "is particularly important as exposure to HAP is often disproportionately borne by underserved and underrepresented communities." (87 FR 7624; 7646). The commenters said that that individuals prefer equality in health risks over equality in income and are willing to accept greater additional risk overall in exchange for equality reveals the worth of these improvements. The commenters said that improvements in equity not only provide an altruistic benefit to society—an important, yet previously unmentioned, class of benefits—but also address risks to the most exposed individuals and to sensitive populations.

Commenters stated that as the EPA has acknowledged, consumption of Hg-contaminated fish and shellfish is the primary pathway by which Hg exposure occurs in the U.S. The commenters said that in the Southeast US, individuals living near coal-fired power plants often are people with low incomes and people of color; for these individuals, fishing can provide an inexpensive food source. Because of higher rates of fish consumption, however, these individuals are also disproportionately impacted by Hg emissions from coal-fired power plants. The commenters said that the EPA, in the 2011 RIA, assessed the impacts from power plant Hg emissions on demographic groups with significant potential risks of Hg exposure, including African Americans with low incomes living in the Southeast and with high rates of consumption. The commenters said that looking at the only subset of public health benefits attributable to reductions in Hg emissions that could be quantified at the time, *i.e.,* IQ loss in children, the EPA noted that "an African-American child in the Southeast born in 2016 to a mother consuming fish at the 90th percentile of published subsistence-like levels" would experience a substantial loss of

IQ points “as a result of in-utero [methylmercury] exposure from all sources in the absence of a Toxics Rule.” (2011 MATS RIA at 4-3.)

Commenters urged the EPA to adopt a stricter Hg standard not only for low-rank coal units but also for not-low-rank coal units in order to reduce the impacts on individuals and communities who have been disproportionately burdened from exposure to Hg and other HAP. The commenters said that Dr. Sahu compared Hg emissions at Plant Barry, Winyah, and Wateree, based on the current standard for Hg of 1.2 lb/TBtu, with the expected reductions in emissions from a tighter standard of 0.15 lb/TBtu. Under the current limit, Plant Barry unit 5 would have been permitted to emit 44.81 pounds in 2022 based on the actual heat input for that year, although actual emissions reported were 15.62 pounds. Under the stricter limit of 0.15 lb/TBtu, emissions in 2022 would have been reduced to 5.60 pounds. They said at Wateree unit 1 for 2022, permitted emissions of Hg would have been 12.91 pounds under the current limit of 1.2 lb/TBtu.; actual reported Hg emissions for 2022 were 4.38 pounds; and Hg emissions under a limit of 0.15 lb/TBtu would have been limited to 1.61 pounds. The data show similar results for Winyah unit 2 for 2022: under the current limit, Winyah could emit 10.50 pounds of Hg; actual reported Hg emissions were 4.41 pounds; and under a stricter limit of 0.15 lb/TBtu, Hg emissions from this unit would have been limited to pounds.

Commenters stated that in the Southeast, the EPA’s 2021 watershed-based risk assessment indicates that under the current standards low-income Black subsistence fishers face elevated risks of fatal heart attacks from power-plant methylmercury exposures.

Response 4: The EPA acknowledges support for standards finalized in this rule. The EPA did not propose a lower Hg limit for not-low-rank coal units. The EPA also acknowledges that certain populations may experience greater exposure to methylmercury and some of the methylmercury may be the result of deposition from EGUs. The risk assessments that the EPA undertakes are designed to account for vulnerable subpopulations. The EPA stands by its 2020 RTR which showed that emissions of HAP from coal- and oil-fired power plants have been reduced such that residual risk is at an acceptable level. Responses to similar comments on the risk findings of the 2020 RTR can be found in Chapter 10. The finalized standards are anticipated to further reduce mercury emissions.

Comment 5: Commenters stated that a disproportionate number of people of color and people with low incomes, compared to the states’ overall demographics, live near Plant Barry in Alabama, and the Winyah and Wateree plants in South Carolina. Emissions from these power plants of acid gases—like the emissions of Hg and non-Hg metal HAP—also have disproportionate impacts on people of color, Black people, and people with low incomes. The commenters said that Dr. Sahu and Dr. Grey’s air dispersion modeling last year for Plant Barry and the Winyah also looked at SO_2 emissions, an acid gas surrogate. They said that as with Hg emissions and non-Hg metal HAP, the maximum impact for SO_2 was “predicted to be around 5 km or less distant from the plant, with potential impacts on those living near the plants.” (Sahu 2022 Technical Analysis at 2.)

Commenters stated that a stricter acid gas standard could alleviate some of the impacts that people of color and low-income communities disproportionately experience from exposure to acid gas emissions from Plant Barry, Winyah, and Wateree. The commenters said that Dr. Sahu analyzed emissions of HCl under the current standard of 0.002 lb/MMBtu for Plant Barry Unit 5 in Alabama, and for each unit at Wateree and Winyah in South Carolina, in comparison to the use of a stricter standard for HCl of 0.0006 lb/MMBtu. For Plant Barry, using the year 2022 heat input, emissions of HCl were limited to 74,687 lb; under a stricter limit of 0.0006 lb/MMBtu, emissions of HCl would have been limited to 22,406 lb. For Wateree Unit 1 and Winyah Unit 4, the results were also significant: under the current HCl limit, emissions of HCl at Wateree were limited to 21,519 lb, while under the proposed limit of 0.0006 lb/MMBtu, emissions would be limited to 6,456 lb. The commenters said that finally, at Winyah Unit 4, under the current limit for HCl, emissions for 2022 were limited to 2,328 lb, whereas using the stricter limit for HCl of 0.0006 lb/MMBtu, emissions of HCl would have been limited to 698 lb.

Response 5: The Agency did not receive comments to change the outcome of the technology review proposing no changes for acid gas standards.

Comment 6: Commenters stated that lignite units carry a very low air toxics risk, which is well below acceptable standards. The commenters said that the EPA's risk analysis applies to sensitive populations and takes into account the current emission reductions at the current fPM and Hg limits. The commenters said that however, the proposed fPM measures come with substantial electricity costs that all communities must shoulder. The EPA must weigh the costs of imposing these emission reductions in areas supplied by cooperatives in which the end user will face higher electricity costs. The commenters said that nationally, low-income households spend a larger portion of their income on home energy costs (*e.g.,* electricity, natural gas, and other home heating fuels) than other households spend.

Response 6: The Agency conducted a review of the 2020 Technology Review pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since the original MATS rule was promulgated. EPA's response to comments with respect to the revised fPM standard are presented in section IV.C of the preamble. EPA's response to comments with respect to the revised Hg limits are presented in section V.C of the preamble. With respect to the comment on electricity price impacts on end users, we note the RIA finds that rate impacts on average are well under 1% nationally.

CHAPTER 9

9. Statutory and Executive Order Reviews

9.1 Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Comment 1: The commenters urged the EPA to convene an interagency process and complete a cumulative impact analysis of the reliability issues associated with its entire "power sector strategy" before finalizing this rule. The commenters stated convening an interagency process aligns with Executive Order 13563, signed by President Obama, reaffirmed in President Biden's Executive Order 14094, "Modernizing Regulatory Review."

The commenters said the EPA recently signed a memorandum of understanding (MOU) with the U.S. Department of Energy promising "interagency cooperation and consultation on electric sector resource adequacy and operational reliability." The commenters stated there is no information in the docket about how the agencies will or have worked together and with FERC, NERC, and other stakeholders toward this goal and no public meetings have been held to further the goals of the MOU.

The commenters further stated that as part of this interagency process, the EPA should complete a cumulative impacts analysis of the reliability impacts of its power sector strategy that is informed by direct expert consultation with FERC, NERC, RTOs, and other grid experts. The commenters stated as part of its plan to remake the power sector, EPA has promulgated or proposed six rulemakings, including the proposed MATS RTR at issue in these comments, the Clean Water Act Effluent Limitation Guideline proposal, the recently finalized Ozone Transport Rule, the proposed rulemaking to lower the NAAQS for PM, and most recently, the new GHG emissions guidelines for existing coal-fired electric generating units. The commenters said the EPA is also continuing to implement the 2015 Coal Combustion Residue rule and responding to facility requests to continue to operate certain surface impoundments under the Part A and Part B programs promulgated more recently. The commenters stated these decisions alone impact 55 GW of electric generating capacity in 19 states. They said because all these rules affect the power sector, coal generation, and reliability, the impact of one rule cannot be understood without understanding the impacts of all the others.

Response 1: In parallel with the development of various rules that cover pollution from fossil fuel-fired electric generating units, the EPA has consulted a wide range of stakeholders, including other Federal agencies, reliability experts, and grid operators. To deepen this coordination, on March 9, 2023, EPA and DOE issued a Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability to provide a framework for interagency cooperation and consultation on electric sector resource adequacy and reliability. The MOU outlines activities to monitor and share information to support the continued reliability of the electric system, including regular outreach and consultation with FERC, NERC, and other reliability and electricity grid-focused entities. There have been numerous events and engagements as part of the MOU effort, which have helped enhance linkages within the EPA and deepen our relationship with DOE. Perhaps most importantly, the MOU framework has allowed a more robust and focused engagement with important stakeholders who are critical to ensuring that the grid operate efficiently and reliably. This process is not linked to any one regulatory effort or final action, but supports EPA's efforts to better understand the various the diverse set of perspectives. However, this process does not substitute for EPA's public comment process as part of individual regulatory efforts. Each regulatory effort includes technical support information and data related to resource adequacy and reliability, as it relates to that action. EPA plans release additional information on the Reliability MOU develops.

The final rule covers a small number of EGUs, and as shown in section 3.5.4 of the RIA for the final rule, the EPA does not project incremental changes in operational capacity to occur in response to the final rule. Because the EPA projects no incremental changes in existing operational capacity to occur in response to the final rule, the EPA does not anticipate this rule will have any implications for resource adequacy (see Resource Adequacy Analysis Technical Support Document, available in the docket). As EPA develops regulations, it reflects the cost of final actions and rules in the baseline. As such, the public has the ability to understand the incremental and cumulative impacts of various actions over time. For example, this action includes the costs and requirements of previously finalized efforts like the Final GNP and CCR actions. As future actions are finalized, those will include the requirements of this final action. While the EPA will continue to evaluate and isolate the potential impacts of final actions individually, the EPA also provides technical support information and data where relevant and as they relate to other regulations and the potential cumulative impacts.

For example, the EPA analyzed projected resource adequacy impacts of several recently finalized EPA rulemakings: the LDV, HDV and MDV (collectively "Vehicle Rules), Final 111 EGU Rules, ELG and MATS (collectively "Power Sector Rules") and found that, whether alone or collectively, these rules are unlikely to adversely affect resource adequacy. For further discussion, see Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS Technical Memo, available in the docket. Additionally, the EPA estimated the collective impacts of the vehicle rules, final 111 EGU rules, MATS and ELG. For further discussion of this modeling, see IPM Sensitivity Runs Memo, available in the docket.

CHAPTER 10

10. CAA Section 112(f) Residual Risk, 2020 petition for reconsideration

Comment 1: Commenters supported the Agency's findings that the 2020 Residual Risk Review was sound, and the commenters supported the EPA's proposed determination that the acid gas standards for coal- and oil-fired EGUs and IGCC units do not need revisions. Commenters said that the 2020 RTR findings are consistent with risk analyses completed by electric utility researchers in a pair of June 2018 reports that concluded that inhalation and multi-pathway health risks from coal-fired EGUs were well within the EPA's established acceptable risk thresholds and commenters provided links to the 2018 reports. Commenters said neither the residual risk review nor technology review justify revising the MATS. Commenters cited, agreed with, and supported the EPA's finding in the 2020 RTR that current HAP emissions from EGUs provide an ample margin of safety for health impacts and impart no adverse environmental impacts.

Commenters said that the EPA must revise MATS to protect human health near the Colstrip Plant and across the country because these emissions cause cancer and serious health impacts with disproportionate impacts on disadvantaged and environmental justice communities. Commenters said that the EPA should consider the incremental benefits of reducing HAP emissions below the current acceptable risk and health thresholds like the EPA did under the Benzene NESHAP. Commenters said it is consistent with cost-benefit analysis to weigh incremental benefits of Hg and non-Hg metal emission reductions under CAA section 112(f)(2), and commenters said the EPA should assess the risks posed by lead (Pb) emissions considering the Centers for Disease Control (CDC) has found no safe level of lead exposure in children's blood. Commenters said the EPA should consider multipathway and cumulative exposure under CAA section 112(f)(2) because the EPA has not considered how below-threshold risks may combine with other exposures to form a cumulative burden that potentially exceeds the threshold, particularly in "hot spot" communities like those neighboring the Colstrip Plant in Montana.

Commenters said that the EPA's determination in 2020 to impose no standards under CAA section 112(f)(2) is relevant to the proposal because evidence of risks has grown since 2020, and the new evidence should be considered under CAA section 112(f)(2).

Commenters said that in a future rulemaking, the EPA should reconsider its 2020 determination that risks remaining after implementation of MATS provide an ample margin of safety. Commenters cited their petition for reconsideration, associated risk analyses (including new data), and held that the EPA's 2020 determination failed to evaluate all of the risks posed by HAP emissions from coal- and oil-fired EGUs.

Commenters also presented the results of new research on sociodemographic disparities on exposure to Hg emissions from EGUs and recommended that the EPA reconsider its residual risk analysis in the 2020 Final Action (85 FR 31286). Commenters said that recent methylmercury exposure data could support strengthening the Hg standard for lignite units and cited the preamble to the Benzene standard (54 FR 38044) indicating that the EPA has the authority to consider effects on the most exposed individuals and on the general public.

Commenters said that the 2020 Residual Risk Review indicate that no EGU emissions result in exceedances of the 2001 methylmercury Oral Reference Dose (RfD), but these commenters supported the proposal's recognition that human health effects can occur at exposures below the 2001 RfD. Commenters stated that this 2001 methylmercury RfD value does not reflect consideration of recent analyses and studies, including those addressing various neurological (*e.g.*, IQ) and cardiovascular endpoints. Such a consideration of these and other studies would likely lead to a more protective RfD value. Commenters cited a recent study that concludes that EGU-related Hg deposition plausibly can result in exposures that exceed the RfD for the most highly exposed individuals. The commenters said that the EPA should carefully consider these new findings in areas impacted by emissions from lignite-fired EGUs and urged the EPA to resume efforts to update the methylmercury RfD.

Commenters said incremental reductions in emissions of Hg and acid gases (and associated reductions in risk) are worth pursuing. Commenters cited recent studies that confirmed the EPA's prior risk assessments underestimated risks and cited multiple risk-related objections presented in their petition for reconsideration of the 2020 RTR. Commenters said it was not possible to raise these risk-related issues during the public comment period and said that the EPA should initiate a reconsideration proceeding for the 2020 RTR.

Response 1: Because we did not reopen the 2020 Residual Risk Review, many of these comments fall outside the scope of this rulemaking. We note, however, that the EPA acknowledges support for the 2023 Proposal and the findings of the 2020 Residual Risk Review. The EPA also acknowledges that it received a petition for reconsideration from environmental organizations that, in relevant part, sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review, which the EPA continues to review and will respond to in a separate action.[10]

Regarding multipathway and cumulative assessments, most or all receptors in these assessments receive exposures to multiple pollutants rather than a single pollutant, we estimate the aggregate health risks associated with exposure to all the HAP from a particular source category.

Regarding health impacts in vulnerable groups, EPA agrees with the points made by the commenters, including the presence of specific subsistence-fisher populations in specific regions of the country potentially impacted by U.S. EGU-sourced Hg (*e.g.,* tribal populations in the Midwest, people of color in the Southeast, and other populations in the vicinity of U.S. EGUs). We acknowledge that population subgroups, may have a potential for risk that is greater than the general population due to greater relative exposure and/or greater susceptibility to the toxicant. The assessments we undertake to estimate risk account for this potential vulnerability. With respect to non-cancer toxicants, the assessments rely on the EPA's hazard identification and

[10] See Docket ID No. EPA–HQ–OAR–2018–0794– 4565 at www.regulations.gov.

dose-response values that have been developed to be protective for all subgroups of the general population, including children.

The EPA thanks one commenter for their recommendation for future rulemakings, EPA will continue to operate under the authority of the CAA to protect public health.

Regarding the findings of Dai et al., 2023 (Harvard paper), which was cited by several commenters, EPA acknowledges the merits of this screening-level assessment, which corroborates EPA's screening results with both identifying the same areas of potential concern. In the 2020 Residual Risk Review, using the same emissions data, the EPA performed a refined site-specific analysis on this most impacted area in North Dakota at a much finer resolution than the screening analysis reported by Dai et al., (2023). EPA's deposition calculation (4-5%) more accurately reflects the local US EGU deposition at this site than Dai et al.'s (8%). Given the low risk, applying the 8% deposition figure would not change the risk conclusions for this site. EPA's refined site-specific analysis provides the most accurate estimate of the highest risk potential from nearby US EGU emissions. By using these location-specific data (including fish tissue methylmercury data, Hg deposition and the assessment of the potential for activity by specific subsistence fisher populations), the risk assessment was based on a relatively high degree of spatial resolution in characterizing the existence of significant exposure and risk to U.S. EGU-sourced Hg. Our multipathway assessments follow Scientific Advisory Board (SAB)-approved methods and Dai et al., 2023 does not identify any reason why we should deviate from our standard practices at this time.

The EPA is aware of new scientific research on sociodemographic disparities on exposure to Hg emissions from EGUs. The EPA's multipathway assessments follow Scientific Advisory Board (SAB)-approved methods and the new research cited by commenters does not identify any reason why the EPA should deviate from our standard practices at this time. The EPA is also aware that new scientific data have become available since the 2001 IRIS assessment for methylmercury was completed, including both experimental studies and epidemiological evaluations of exposed human populations. However, it is premature to estimate what, if any, revisions to the IRIS assessment for Hg may be needed until a comprehensive evaluation is conducted and such an evaluation cannot be completed at this time. More information about the IRIS process is available on the IRIS website.[11]

The EPA acknowledges the potential for Hg emissions to impact vulnerable communities and natural resources. Commenters noted significant improvements in Hg levels and attributed this to MATS. The proposed standards are anticipated to further reduce Hg emissions.

Comment 2: Commenters said that these low risks indicate that the EPA should not impose almost $2 billion of cost when there is no benefit, particularly in a sector that is rapidly reducing emissions. Commenters said that the sector will be retiring most, if not all, affected sources in a little over a decade, cited *Michigan v. EPA*, and said that the Court's holdings that risk benefits should be weighed against costs are relevant to the proposal. Commenters said that decisions by

---

[11] https://iris.epa.gov/ChemicalLanding/&substance_nmbr=73#status

affected units to achieve significant compliance margins do not necessitate changes to limits and said the proposal does not offer explanation as to why compliance margins would drive emissions standards. Other commenters cited numerous ongoing rulemakings that will apply to electric utility operations and said the EPA's reconsideration of the 2020 finding (that the remaining residual risks under CAA section 112(f)(2) are acceptable) is poorly timed. Commenters from North Dakota said that the EPA's risk analysis indicates that the level of risk presented by North Dakota lignite-powered plants is an order of magnitude lower than the highest risk from any coal-fired plant and that maximum risks are not associated with Hg. These commenters said that the proposal fails to explain the inconsistency between the EPA's risk analysis under CAA section 112(f)(2), which the commenters said shows very low risk, and imposing more stringent controls on lignite-fired units. Commenters also noted the significant differences between the maximum risks at oil-fired plants and the maximum risks at coal-fired plants and asked the EPA to consider whether oil and coal plants should be regulated separately in light of the different levels of risk presented.

Commenters said that the proposal's 2023 RTR contradicts the EPA's 2020 RTR and said the Agency's basis for revising the PM limit is beyond the scope of CAA section 112 requirements. Commenters agreed with the EPA's conclusion that further reductions were not required under CAA section 112(f)(2) because the current standards provide an ample margin of safety. Commenters said the EPA's determination under CAA section 112(f)(2) calls into question the basis for the proposal to increase EGU operating costs. Commenters said that the steep decline in EGU HAP emissions will continue under the current standards as the sector continues to retire or reduce utilization of existing coal-fired capacity.

Commenters said that even though the EPA is not required to consider risk reductions under CAA section 112(d)(6), the potential to reduce emissions of a wide range of highly toxic HAP underscores the need to strengthen the standards.

Commenters agreed with the EPA's "two-pronged" interpretation that CAA section 112(d)(6) imposes technological obligations that are distinct from risk mandates under CAA section 112(f)(2). Commenters said that if the criteria under CAA section 112(d)(6) are met, the EPA must update the standards to reflect new developments, without regard for risk assessments under CAA section 112(f)(2). Commenters compared the periodic technology reviews under CAA section 112(d)(6) versus the one-time risk-assessment under CAA section 112(f)(2) and said that an interpretation that risk assessments under CAA section 112(f)(2) can govern determinations under CAA section112(d)(6) improperly collapses these two expressly separate regulatory tracks.

Response 2: The EPA disagrees with some commenters that given the low risks, the EPA should not impose new standards. As described in the 2023 Proposal preamble (88 FR 24866), and agreed upon by other commenters, Congress intentionally created a two-pronged structure for updating standards for toxic air pollutants that requires EPA to continue assessing opportunities to strengthen the standards under CAA section 112(d)(6) even after residual risks have been addressed under CAA section 112(f)(2). Under this structure, the EPA is obligated to update standards where either the EPA finds it is necessary to provide an ample margin of safety to protect human health or where the EPA finds it is necessary taking into account developments in practice, processes, and control technologies.

The EPA acknowledges the number of power sector rulemakings affecting electric utilities at this time as well as a large number of retirements within the next decade. However, the final emission standards are consistent with CAA section 112 requirements, and are further addressed in the preamble.

Comments regarding costs considerations following from the *Michigan v. EPA* decision are discussed in section 8.4 of this document.

10.1 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Comment 1: The commenters stated that the EPA's proposal fails to comply with Executive Order 13211, "Actions that Significantly Affect Energy Supply, Distribution, or Use." The commenters said numerous experts have informed the EPA that the cumulative impacts of the Agency's "power sector strategy" will have an adverse impact on domestic energy production, supply, costs, and use. The commenters said that the EPA therefore must conduct a more in-depth analysis, in consultation with grid experts, of those potential effects under Executive Order 13211. The commenters argued that the Agency cannot acknowledge the interrelated nature of the "power sector strategy" rulemakings and at the same time pretend that there is no impact to the supply, distribution, and use of energy.

Response 1: Section 3.3 of the RIA summarizes all major rules included in the baseline of this final rule. The inclusion of any potential future rules in the baseline for this final rule would not be informative. EPA notes that future rulemakings will include analysis of this final rule in the baseline.

CHAPTER 11

11. Other Topics

Comment 1: Commenters stated that the EPA failed to publish the proposed regulatory text in the Federal Register (FR) notice for the 2023 Proposal and nowhere in the FR notice did the Agency mention the proposed regulatory text or note that it was available in the docket. They stated that locating the proposed regulatory text was difficult for the following reasons: (i) the docket contained nearly 570 documents (559 of which are in the Supporting and Related Materials category) as of June 23, 2023; (ii) the proposed regulatory text document was titled, "MATS RTR Rule Text Redline Strikeout document," and thus would not appear among the search results if searching via keywords "regulatory text"; and (iii) even a search of "redline" returns 45 documents that must be reviewed to determine whether they contain the final version of the redlined regulatory text. The commenters said the redline is available only on Regulations.gov and is buried as an attachment to a document obscurely titled "Email correspondence confirming EPA OAQPS made edits in response to OMB's Passback no. 1 of the RIA for the MATS RTR (2060-AV53)." They argued that the public cannot meaningfully comment on this redline-even if one is persistent enough to find it-because [the public] cannot be certain the redline reflects the rule being formally proposed.

Commenters stated that by posting the proposed regulatory text as a separate document, the Agency runs the risk not only of stakeholders failing to find it in the docket but also of creating discrepancies between the description of the proposal in the FR and the proposed regulatory text itself. For instance, as to the LEE option for fPM, total non-Hg metals, and individual HAP metals, the FR notice indicates that the option will be removed "no later than 3 years after the promulgation date"; however, the proposed regulatory text (final version) indicates that the option will be available up to 3 years after the effective date of the final rule [*see* 88 FR 24887; Redline Final at PDF p. 100]. The commenters said such discrepancies prevent interested members of the public, potentially affected EGUs, and other stakeholders from receiving adequate notice of the EPA's proposed action and impair their ability to provide informed comments. They said the EPA also runs the risk of running afoul of its statutory duty under the APA to provide the public with adequate notice, particularly if the description of the proposal in the FR notice fails to accurately capture "either the terms or substance of the proposed rule or description of the subjects and issues involved." To ensure that the public is afforded a meaningful opportunity to comment on proposed rules, the minimum 60-day comment period should not run until the public has received fair and adequate notice of the regulatory language, which is best accomplished by publishing the proposed regulatory text in the FR [5 U.S.C. § 553(b)].

The commenters requested that the EPA publish the proposed regulatory text with the Proposal in the FR and that for future rulemakings, the Agency return to its longstanding practice of including the proposed regulatory text in the FR notice for a proposed rule. Such practice would provide clarity around the proposed regulatory action and ensure that all members of the public have adequate notice and an opportunity to comment on the proposed regulatory language.

The commenters stated that the EPA also did not post the RIA for the Proposal until over two weeks into the public comment period (*i.e.,* after over 25% of the public comment period had already run) (EPA-HQ-OAR-2018-0794-5837). They said that given that the CAA requires EPA to consider the costs of its Proposal, (42 U.S.C. § 7412(d)(2)) the Agency's failure to promptly publish the RIA further constrains the public's ability to meaningfully comment on a central element of the Proposal.

Response 1: The 2023 Proposal met all APA and CAA notice-and-comment requirements. Nothing in the APA or CAA requires EPA to publish proposed regulatory text in the Federal Register. The CAA section 307(d)(3) requirement to publish a "notice of proposed rulemaking" is not a requirement to publish proposed rule text. CAA section 307(d)(3) specifies the required elements of a "notice of proposed rulemaking," and "proposed rule text" is not a required element. The APA does not require publication of proposed rule text in the Federal Register either. Section 553(b)(3) of the APA provides that a notice of proposed rulemaking shall include "either the terms or substance of the proposed rule or a description of the subjects and issues involved." Thus, the APA clearly provides flexibility to describe the "subjects and issues involved" as an alternative to inclusion of the "terms or substance" of the proposed rule. See also *Rybachek v. U.S. E.P.A.*, 904 F.2d 1276, 1287 (9th Cir. 1990) (EPA's failure to propose in advance the actual wording of a regulation does not make the regulation invalid where EPA's discussion of the regulatory provisions "clearly describe[s] 'the subjects and issues involved.'").

In addition, EPA stated in the 2023 Proposal that a memorandum showing the rule edits that would be necessary to incorporate the proposed changes to 40 CFR part 63, subpart UUUUU was available in the docket and would be posted on EPA's MATS website. See 88 FR 24858 (April 24, 2023). Although in the past the EPA has at times published proposed amendatory regulatory text, the EPA's practice has varied. See, *e.g.,* Hazardous Air Pollutants: Proposed Regulations Governing Constructed, Reconstructed or Modified Major Sources, 59 FR 15504 (April 1, 1994) ("The proposed regulatory text is not included in the Federal Register notice, but is available in Docket No. A-91-64 or by request from the EPA contact persons designated earlier in this note. The proposed regulatory language is also available on the Technology Transfer Network (TTN), of EPA's electronic bulletin boards."); Federal Standards for Marine Tank Vessel Loading and Unloading Operations and National Emission Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading and Unloading Operations, 59 FR 25004 (May 13, 1994) ("The proposed regulatory text and other materials related to this rulemaking are available for review in the docket."). Even when we do include the proposed text in the Federal Register, we often include a redline version of proposed regulations in the docket for rulemakings to assist the public in understanding the proposed regulatory changes. In our experience, stakeholders find the redline version far more useful than the proposed amendatory language in the format required by the Office of the Federal Register. Although appropriate for the task of revising the CFR, this language can be difficult to assess without the accompanying full regulatory text. Given this, and given that we rarely receive comments on the proposed amendatory language or on proposed regulatory language at all, we determined that for rulemakings such as these, it would be more efficient to take the approach here of making both easily accessible but not including the proposed amendatory text in the notice.

The final RIA experienced delays in posting in the docket, however the final OMB passback version, which was the same as the final RIA, was available.

Comment 2: Commenters stated that the EPA's actions in the present rulemaking have no bearing on its March 2023 reaffirmation that it is "appropriate and necessary" to regulate coal- and oil-fired EGUs under CAA section 112. They stated that the threshold determination, first made in the year 2000 and reaffirmed in 2012, 2016, and 2023, cannot now be challenged and has always been legally distinct from—and, under the statutory design, was to be temporally removed from—any revisions that the Agency makes to the original standards.

Response 2: The commenter is correct that the appropriate and necessary determination is a distinct action that cannot be challenged under this rulemaking.

Comment 3: Commenters said that given what they described as the inordinately long delay to reinstate the A&N finding for the MATS, the EPA must finalize this proposal with the most stringent provisions that afford more public health protection, no later than the end of 2023. They argued that any delay in implementing stronger limits on Hg and other hazardous air pollution means accruing risks of health harms to babies and fetuses that could follow them into adulthood.

Response 3: The EPA is finalizing the proposed rule as expeditiously as possible.

Comment 4: Commenters stated that a cycle time equal to or less than 15 minutes is currently required for CEMS in various places in the proposed rule:

- Table A-1 - Required Certification Tests and Performance Specifications for Hg CEMS (page 25140),
- Table A-2 - Minimum Required Certification Tests and Performance Specifications for Other Monitoring Systems (page 25141),
- §63.10010: Monitoring, installation, operation, and maintenance requirements (pages 25110-25113).

The commenters said they strongly recommend that these references to 15 minute cycle times be eliminated since they are not required for health effects or regulations and reference methods require sampling times of about four hours (4 dscm) at these low concentrations. They said in addition, the proposed cycle time is not consistent with PS12 A or Cement MACT rules.

Response 4: The Agency acknowledges the commenter's suggestions but notes that while revised non-Hg metals emission limits are included in the rule, compliance is to be determined based on a revised fPM emission limit using PM CEMS. Moreover, as fPM correlation testing will now be based on a minimum mass sample collection – which is expected to reduce sampling time duration. As mentioned previously, should an EGU owner or operator desire to use a continuous monitoring method to determine compliance with individual or total non-Hg metals, she or he may request approval from the Administrator to use an alternative test method under the provisions of 40 CFR part 63.7(f).

Comment 5: Commenters said that the EPA did not provide all available information to reproduce their analysis. They said in the proposed rulemaking, the Agency has omitted critical information from the docket that would allow a complete evaluation of the methodology used to set the standard. They said examples of this information include the following:

- Computer code associated with data processing and analysis – The commenters said that unlike the initial MATS rulemaking, in which the Agency included all associated test data and statistical analysis in various spreadsheets, the proposed rulemaking utilized Python code to process underlying datafiles for the purpose of setting the standard. They stated that the Agency has not provided a copy of the raw code, a description of code functionality, or any associated input or output files.
- Spreadsheet summarizing statistical analysis – The commenters said the EPA may also have additional spreadsheets that provide the detailed statistical analysis used to determine the proposed standards. They said that while the data itself is summarized in a spreadsheet and the analysis is summarized in a PDF memo, the spreadsheet showing the detailed calculations has not been provided.

The commenters said they are aware of several requests to the EPA to obtain the computer code and analysis spreadsheet that were made early in the comment period. They asserted that the Agency did not respond, or the response was "the data has been provided," which they said suggested that it is up to commenters to analyze the data in order to reproduce the results. The commenters said notwithstanding there may be issues obtaining some of the data itself, the EPA should provide all supporting calculations that enable the regulated community to review the methodology in detail as providing only the raw data and final results does not provide sufficient transparency.

Response 5: The 2023 Technical Memo (Docket ID No. EPA-HQ-OAR-2018-0794-5789) contains all necessary information to recreate the PM analysis. The Python code read in the 2017, 2019, and 2021 fPM compliance spreadsheet (Docket ID No. EPA-HQ-OAR-2018-0794-5561) and quarterly 30-day rolling average PM CEMS data files and calculated each quarter's 99th percentile. These calculations, as well as summary statistics, can be calculated in the Excel files provided in the docket and can be verified with the Agency's results in Appendixes B and C in the 2023 Technical Memo. It is important to note that the 2017, 2019, and 2021 fPM compliance spreadsheet contains information for EGUs not affected by this rulemaking. This file was created by merging three independent spreadsheets representing fPM data pulls over the past several years. The 2017 information was pulled in 2018, the 2019 data was pulled in 2021, and the 2021 information was pulled in 2023. Information was collected for the fleet operating at that moment in time, and often to inform EPA on the power sector broadly, and in some cases EGUs have converted to gas or retired and not relevant for this rulemaking.

The code used the lowest demonstrated fPM rate and PM upgrade assumptions from Table 5 of the 2023 Technical Memo to assign PM upgrades for each EGU for each potential standard. Python code for the 2023 Proposal, in addition as the final, was not provided since it contained deliberative and internal information. The Agency recognizes the importance of transparent and accessible analytics supporting the rule. The revised PM analysis is summarized in the 2024

Technical Memo entitled “2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category.” In addition, an attachment to this docket entry is Python code summarizing and plotting the additional fPM compliance data the Agency reviewed since proposal. An Excel spreadsheet is also an attachment to this docket entry, which more clearly and concisely documents PM control assumptions for each EGU for each fPM limit assessed.

Comment 6: Commenters stated that they recommend that the EPA further strengthen the MATS by revisiting recent actions addressing EBCR burning EGUs. They asserted that in its current proposal, the Agency does not address EGUs burning EBCR and said in its 2020 rulemaking (EPA–HQ–OAR–2018–0794; FRL–10007–26– OAR) the EPA established a subcategory of existing EBCR-fired EGUs for acid gas HAP and surrogate SO_2 limits under MATS, with a surrogate SO_2 compliance limit of 0.6 lb/MMBtu.

Commenters said that according to the CAA, the MACT “floor” is based upon:

> “The average emission limitation achieved by the best performing five sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory, for categories or subcategories with fewer than 30 sources.”

Commenters said that national parks in West Virginia and Virginia have been historically exposed to excessive levels of sulfur deposition, resulting in removal of essential nutrients from soils and associated reduced tree and herbaceous species growth and survival. Commenters said sulfur deposition and acid gas emissions have decreased over the past 40 years, but current deposition rates are still having adverse effects on ecosystems. Commenters said that reducing the SO2 limit under MATS would likely result in reductions of all acid gases, including HF.

The commenters stated that at the time of its 2020 rulemaking, the EPA calculated the current average monthly SO_2 lb/MMBtu emission rate for each EBCR-burning EGU for the period of January 2015 through June 2018. They said that because no HCl emissions data had been submitted for the currently-operating EGUs, and SO2 lb/MWh emissions data were available for only two of the EGUs, the EPA determined that the MACT beyond-the-floor value of 0.60 lb SO_2/MMBtu was appropriate, with an effective date of April 15, 2020. The commenters said since then, SO_2 emissions data has become available in CAMD and they provided a table with SO_2 emissions data from CAMD for six EBCR-fired EGUs – Grant Town Power Plant #1A, Grant Town Power Plant #1B, Scrubgrass Generating Plant #1*, Scrubgrass Generating Plant #2*, Colver Green Energy, and Ebensburg Power Company [The table included a footnote which stated that the Scrubgrass EGUs frequently exceeded the 0.6 lb SO_2/MMBtu monthly limit. To determine the performance capability of the SO_2 emission controls, they reduced any monthly average exceeding the 0.6 lb/MMBtu standard down to the standard limit when calculating the average emission rates.]

The commenters said that these EBCR-fired units are of special interest to them because of their proximity to Shenandoah National Park, a Class I area (they provided a map of EBCR facilities in close proximity to Shenandoah National Park). They said that the combination of emissions and locations of these facilities results in their relatively high impacts at Shenandoah National Park. The commenters said that for example, their review of area of influence analyses generated by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) regional planning organization indicates that out of over 63,000 facilities included in the assessment, the Grant Town facility ranks #15 for sulfate impacts at the park; Colver ranked #43, Ebensburg #60, and Scrubgrass ranked #75.

The commenters said four of the six EBCR-fired EGUs achieved continuous compliance with the 0.6 lb SO_2/MMBtu surrogate limit on a monthly basis (and they provided an email address for the EPA to contact them for the source EBCR emissions data and associated charts). They said that according to CAMD, in 2022 these six EBCR-fired EGUs had a heat input of 28,826,617 MMBtu and emitted 7,728 tons of SO_2. The commenters said that if the fleetwide average SO_2 emission rate were reduced to 0.50 lb/MMBtu, the reduction in annual SO_2 emissions would be over 520 tons annually.

The commenters said that of the six EBCR-fired EGUs, Ebensburg and Scrubgrass may have difficulty in complying with a lower (0.5 lb SO_2/MMBtu) limit. For example, the Scrubgrass EGUs frequently exceeded the 0.6 lb SO_2 monthly limit (as shown in the chart below). Because of this, they said they investigated addition of DSI, SDA, and wet FGD to the units at these facilities. The commenters provided tables of their results are in two tables (Table 4. Estimated Scrubgrass Power Plant SO_2 Control Costs and Table 5. Estimated Ebensburg Power Plant SO_2 Control Cost). They said that in order to determine the performance capability of add-on SO_2 emission controls for these units, their analyses reduced any monthly average exceeding 0.6 lb/MMBtu down to the 0.6 lb/MMBtu limit when calculating the average emission rates.

The commenters said that to estimate costs of adding DSI, they applied the 2022 methodology developed by Sargent & Lundy for EPA's Retrofit Cost Analyzer (but did not include Owners' Costs or AFUDC). Even though DSI with milled Trona and a downstream baghouse is capable of achieving 90% SO_2 control, their analyses assumed the lowest control efficiency recommended (70%) to minimize costs. The estimated controls were under-$5,000/ton to control SO_2 which is very cost-effective and should easily allow compliance with the MATS. The commenters concluded that it is likely that DSI could achieve greater emission reductions than assumed in the NPS analysis, indicating that DSI may be an even more cost-effective emission control strategy for the EBCR.

The commenters said that their analyses also used the CCM workbook to estimate costs of adding SDA and wet FGD. The cost effectiveness of adding wet FGD to such small boilers was marginal at Ebensburg at just over $10,000/ton and prohibitive at Scrubgrass at over $17,000/ton. But said on the other hand, the cost effectiveness of SDA was acceptable at Ebensburg and marginal at Scrubgrass, compared to the $11,000/ton (2016$) cost threshold EPA used in its recent "Good Neighbor Rule" (when converted to 2021$, the Good Neighbor cost threshold would be over $14,400).

The commenters concluded that emissions from EBCR-fired units produce relatively high impacts at Shenandoah National Park and they recommended that the EPA revisit its recent actions regarding EBCR and consider a lower SO_2 surrogate limit. They said for example, if the surrogate limit were reduced to 0.50 lb SO_2/MMBtu, SO_2 emissions could be reduced by over

520 tons (7%) annually and if DSI were added to the Ebensburg and Scrubgrass units to comply with a lower limit, even greater SO_2 reductions could be achieved.

Response 6: As noted by the commenters, the 2023 Proposal did not address the acid gas standard for EBCR-fired EGUs. As such, these comments are outside the scope of the proposed action and no response is necessary.

Comment 7: Commenters stated that the federal government has long known that burning coal causes dangerous climate change that imperils the health and wellbeing of American children and future generations. They said that the environmental consequences of burning coal are well documented and are contributing to the catastrophic heat, drought, and wildfires terrorizing the West coast and hurricanes, flooding and tornadoes horrifying the East coast. The commenters said that the local pollution to air and water from coal combustion also harms people's health and threatens aquatic ecosystems and land, including agriculture that depends on access to clean water. The commenters stated that to reduce hazardous pollution from coalfired power plants, protecting our planet and improving public health for all and ensure historic protections for communities across the nation, especially for our children and our vulnerable populations, the EPA needs to set standards that end coal-fired plants, not strengthen or update the standards for coal-fired power plants to continue operating.

Commenters stated that there is simply no legal, scientific, or economic basis to continue burning coal, as was proven in the recent children's constitutional climate trial, *Held v. Montana* in Helena Montana, June 12-20, where leading scientists testified that coal endangers children's health and powering every state in the nation on 100% clean renewable energy is not only technically feasible right now, but is economically beneficial and will save states and consumers billions of dollars in energy bills. See Expert Report of Dr. Jacobson and Trial Testimony in Held v. Montana. They said that coal emits more CO_2 per unit of energy produced than other fuels—in 2022, coal provided approximately 10% of energy consumed in the U.S., yet was responsible for 19% of energy-related CO_2 emissions (U.S. EIA, *Monthly Energy Review, Tables 1.3 and 11.1* (Mar. 2023)).

Commenters stated that scientists, policymakers, and federal officials all the way up to the White House have known for decades that [the U.S.] needed to stop extracting and burning coal. The commenters said that an EPA report in 1983 during the Reagan administration found that coal combustion should be eliminated by the year 2000 in order to avoid dangerous temperature increases from climate change (US EPA, *Can We Delay a Greenhouse Warming?* (Washington, DC, Sept. 1983),
https://nepis.epa.gov/Exe/ZyPDF.cgi/9101HEAX.PDF?Dockey=9101HEAX.PDF). The commenters said that the EPA is the sole federal agency with express statutory authority and duty to protect the airshed from pollution that harms children and how children and future generations are affected by your methods and actions should be your most important lens, as they are the most vulnerable, the politically powerless, and the least capable of protecting themselves. The commenters argued that children require special protection under the law.

Commenters stated that excess accumulation of GHGs in [the] atmosphere results in an Earth energy imbalance and thus an accumulation of heat in [the]Climate system. They stated that the best available science informs that Earth's energy balance can only be restored by returning the atmospheric CO_2 concentration to below 350 ppm by 2100. The commenters said that experts have opined that it is economically and technically feasible to achieve the science-based GHG emission reduction target of close to 100% by 2050, while simultaneously enhancing sequestration capacity of sinks to draw down historical cumulative CO_2 emissions, placing the U.S. on an emissions trajectory consistent with returning atmospheric CO_2 to below 350 ppm by 2100, which would bring long-term heating of the Earth back down to approximately 1.0°C above preindustrial temperatures, stabilizing the climate.

Commenters stated that the current increased average temperatures of 1°C and greater (now at ~1.2°C) are already dangerous according to the IPCC (IPCC Sixth Assessment Report (AR6) (2023)). They argued that basing policies and decisions that align with temperature targets of 1.5°C is catastrophic for our children and posterity (IPCC, Overarching Frequently Asked Questions: FAQ 3). The commenters said that the IPCC special report on Global Warming of 1.5°C (2018) stated that allowing a temperature rise of 1.5°C "is not considered 'safe' for most nations, communities, ecosystems and sectors and poses significant risks to natural and human systems as compared to the current warming of 1°C (high confidence)." (M.R. Allen et al. (2022)). The 2023 IPCC Summary for Policymakers for the Synthesis Report (AR6) stated: "Risks and projected adverse impacts and related losses and damages from climate change will escalate with every increment of global warming (very high confidence). They are higher for global warming of 1.5°C than at present, and even higher at 2°C (high confidence)" (IPCC Sixth Assessment Report (AR6) (2023)). The commenters said that medical experts have recently recognized that "[t]he science is unequivocal; a global increase of 1.5°C above the pre-industrial average and the continued loss of biodiversity risk catastrophic harm to health that will be impossible to reverse." (Lukoye Atwoli et al. (2021)). The commenters concluded that as such, 1.5°C should not be used to guide U.S. policy that is required to be based on best available science and the EPA should not be advancing policies that knowingly make the climate crisis worse, and potentially unsolvable. (The commenters provided several references.)

Response 7: The EPA acknowledges and thanks the commenters for providing these comments. In this action, the EPA is fulfilling its statutory duty under CAA section 112 to set standards for emissions of HAP that "require the maximum degree of reduction in emissions of the hazardous air pollutants . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable." 42 U.S.C. 7412(d)(2). On May 23, 2023, the EPA proposed actions addressing greenhouse gas emissions from fossil fuel-fired EGUs. See 88 FR 33240.

Comment 8: The commenters stated that the Agency's decision to re-evaluate MATS, is timely and appropriate as Hg and Hg-containing compounds, particularly methylmercury, are highly neurotoxic. They said exposure causes permanent damage to various organs and developing brain is particularly susceptible and that the elimination of Hg emissions is the most effective means to reduce this threat. The commenter exhorted the Agency to promulgate a rule that reduces Hg emissions by EGUs to the lowest possible amount using MACT systems. In addition, this must be done in a manner that does not create EGUs that are expected to have operational life-times that extend into the indefinite future while they continue to emit GHGs, most notably CO_2.

The commenters urged the Agency to move more rapidly to enact this rule. They said that every day of delay causes more damage to the health of Americans. They argued that a partial solution to this dilemma has been created by the Agency by its near-simultaneous announcement of 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. They commenters stated that prompt promulgation of both rules should assure better protection of the health of Americans, particularly vulnerable populations that include children, the elderly and those with chronic diseases, while simultaneously combating the climate emergency.

The commenters said that although the first well-documented cases of methylmercury poisoning did not occur until the 1800s, the condition was demonstrated most clearly by the studies of children exposed to this neurotoxin in what became known as Minamata Disease. (Barrett JR. *An uneven path forward: the history of methylmercury toxicity research*. 2010. National Institute of Environmental Health Sciences.; Ui J. Chapter 4 Minamata Disease. In: Ui J, editor. *Industrial Pollution in Japan*. Tokyo, Japan: United Nations University Press; 1992.) The commenters said that the Minimata outbreak was caused by methylmercury discharges into Minamata Bay in Japan and eventually there were approximately 3,000 cases with just over 1,700 deaths from this disaster (Japan-guide.com. *Minamata Disease Related sites*, http://www.japan-guide.com/e/e4527.html. 2011). They said that the methylmercury poisoning is manifested by poor coordination (ataxia), loss of sensation and muscle strength in the hands and feet due to peripheral nerve damage, loss of vision, impaired hearing and speech. In utero exposure may result in microcephaly due to an underdeveloped brain and a clinical syndrome similar to cerebral palsy. A second, serious outbreak of methylmercury poisoning occurred in Iraq in the 1970s.

The commenters said that inhabitants of the Faroe Islands and the Seychelles are another well-studied population, and they said these inhabitants were exposed to methylmercury in their diets that consist of marine animals with high methylmercury levels. The commenters said that the investigative teams that studied these populations used a variety of neurophysiological and other tests (Lockwood AH. *The Silent Epidemic: Coal and the Hidden Threat to Health*. Cambridge, MA: The MIT Press; 2012.). They said the investigators who performed these tests concluded that these inhabitants had sustained neurological damage due to methylmercury at blood concentrations thought to be safe at the time and this necessitated a revision of Hg exposure standards.

The commenters stated that Hg enters the environment by natural mechanisms, such as volcanic eruptions, and the results of human activity and that much of this anthropogenic Hg arises as the result of burning coal to generate electricity. They said that coals of all types contain small amounts of Hg and when coal is burned the Hg is volatilized and discharged in flue gases and as particles. The commenters said that the magnitude of the problem can be approached, in part, via the Toxics Release Inventory (TRI) that tabulates air emissions of Hg. The 2021 TRI lists a total 35,580 pounds of Hg and Hg-containing compounds released into the air by mandated reporters.

The commenters stated that in the environment, Hg-containing particles form the nidus for the condensation of water vapor to form rain and Hg-containing rainfall enters waterways where it is methylated by the action of bacteria. They said that these methylation reactions are favored in water that is acidic and contains large amounts of dissolved organic material, such as the waterways found in the Santee River basin of the Atlantic coastal plain. (Hughes WB, et al. *Water Quality in the Santee River Basin and Coastal Drainages, North and South Carolina, 1995-98: U.S. Geologic Survey Circular 1206*. U.S. Geological Survey, 2000).

The commenters stated that U.S.-attributable methylmercury is highest in the eastern portion of the country due to proximity of coal-fired power plants. They said this poses risk to children, pregnant women and women who may become pregnant and in this part of the country risks are highest among those who rely on self-caught fish as a significant fraction of dietary protein (EPA. *Revised Technical Support Document: National-scale assessment of mercury risk to populations with high consumption of self-caught freshwater fish in support of the appropriate and necessary finding for coal-and oil-fired electric generating units*. 2011. EPA-452/R-11-009.). The commenters said that methylmercury is both persistent and bioaccumulative reaching the highest concentrations in marine mammals, pisciverous birds and large predatory fish (Driscoll CT, et al. *Mercury Contamination in Forest and Freshwater Ecosystems in the Northeastern United States*. BioScience 2007;57(1):17-28.). The commenter said that this bioaccumulation may lead to concentrations in apex predators that are as much as a million-fold higher than in the water of origin and it follows that consumption of large predatory fish and marine mammals that are at the top of the food chain can lead to methylmercury levels in humans and damage to the vulnerable nervous system. The commenter said that eating large predatory fish is the leading source of methylmercury exposure in Americans. They said that to aid the public in making informed decisions concerning the consumption of fish from lakes and streams, many state and tribal governmental agencies publish advisories describing Hg and PCB exposure risks associated with fish caught in specific bodies of water. For example, the state of Ohio 2022 table of advisories is 16 pages long - most of these advisories are warnings about Hg (*2022 Ohio Sport Fish Consumption Advisory*. 2023). The commenters said that in addition, the EPA and the FDA have published fish consumption advice designed to minimize methylmercury exposure from commercially available sources that is particularly applicable to children and for women who are of child-bearing age (EPA, FDA. *Advice About Eating Fish*. 2023).

The commenters stated that wildfires have become more common, more extensive and hotter as the climate emergency has worsened and substantial amounts of Hg in various chemical forms is present in forests in the organic matter on the forest floor and in subsurface soils. They said that this Hg arises from natural sources, such as volcanoes, and anthropogenic sources, chiefly from the combustion of coal and depending on the characteristics of the fire, this Hg is released into the atmosphere, released into runoff from the burned area or both (Sever M. *Big wildfires mobilize mercury. What are the risks to surface water?* Proc Natl Acad Sci USA 2021;118(27):e2110558118). The commenter said thus, after a fire, the Hg that had been sequestered in forests has the potential increase Hg exposures by direct or indirect mechanisms and this re-release of Hg will become an increasingly important source of this toxicant in the future as wildfires become more problematic as the result of climate change. The commenter said that the importance of this source of Hg and its impact on human health will depend increasingly on the success or failure of efforts to combat the climate crisis and to control emissions by EGUs.

The commenters stated that the authors of a 2005 report used data available at the time to model the financial impact of Hg damage to the brain on Americans (Trasande L, et al. *Public health and economic consequences of methyl mercury toxicity to the developing brain*. Environ Health Perspect 2005;113(5):590-596.; Trasande L, et al. *Mental retardation and prenatal methylmercury toxicity*. Am J Ind Med 2006;49(3):153-158). They concluded that at that time there were between 300,000 and 600,000 children who were born each year with blood Hg levels that were high enough to produce impairment on neurodevelopmental and neuropsychological tests. The commenter noted that the report said reduction in the intelligence of these children was estimated to create an economic cost to society of approximately $8.7 billion per year (range $2.2 billion to $43.8 billion in 2000 dollars). The commenter said that when one considers the impact on society, Hg leads to placing more children in the ranks of those who are intellectually compromised, and a similar number are removed from the ranks of individuals who are intellectually gifted. The commenters said unfortunately, Hg damage to the brain is not a one-time cost – Hg-related impairments last for the life of the individual.

The commenters stated that the FDA website does not list any drugs that are approved for the treatment of methylmercury poisoning and any treatment would be directed at symptoms, such as seizures. They said however, chelation therapy may be indicated for individual patients with acute poisoning. They concluded that this decision must be individualized weighing risks versus potential benefit and is not an appropriate solution to large scale exposure.

Response 8: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

Comment 9: The commenters said that the EPA cannot publish alternative emission limits without first issuing for public comment additional proposed standards and their basis. They said that the rulemaking procedures at section 307(d) of the CAA specifically require that a proposed rulemaking must "include a summary of-(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule" and "All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule." (42 U.S.C. § 7607(d)(3)). They said that furthermore, any final "promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation." (42 U.S.C. § 7607(d)(6)(C)). The commenters said that relatedly, the EPA has "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule" including an obligation to "explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated." (*National Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980) (in the context of a new source performance standard rulemaking procedure subject to 42 U.S.C. § 7607(d)). The commenters said; accordingly, the EPA cannot finalize any emission standard other than those analyzed in the Proposed Rule absent a new proposed rule providing the opportunity for public comment on the necessity, appropriateness, feasibility, and cost effectiveness of any such newly proposed limits. They said to do otherwise would be unlawful and arbitrary.

Response 9: The changes the EPA is finalizing are substantially similar to those the EPA proposed and provide notice and the opportunity to comment on consistent with the EPA's obligations under CAA section 307(d). Further, it is well established that EPA is not required "to select a final rule from among the precise proposals under consideration during the comment period. Rather, incremental changes are permissible so long as the final rule is a 'logical outgrowth' of the proposals highlighted and discussed during the notice and comment period." *Sierra Club v. Costle*, 657 F.2d 298, 352 (D.C. Cir. 1981).

Comment 10: Commenters stated that it was arbitrary for EPA to deny the request for comment extension for the Proposed Rule to account for the interplay and effect of these two related rulemakings on each other. The commenters said that the EPA published the proposed GHG NSPS halfway through the comment period for this 2023 Proposal, and this newly proposed GHG NSPS fundamentally changed the technical and cost analysis with respect to the 2023 Proposal, because if both rulemakings are finalized, sources will have to assess how this different control requirements required by each rulemaking interact with and affect each other rather than simply analyzing the 2023 Proposal requirements by themselves as was required during the first portion of the public comment period.

Response 10: The Agency acknowledges it received requests for a comment period extension that were denied. Comment period extension requests for the GHG NSPS were accepted, and the comment period was extended by an additional 15 days and closed on August 8, 2023.

CHAPTER 12

12. General

Comment 1: Commenters said that the EPA's proposal would strengthen limits on PM pollution from power plants (as a surrogate pollutant for toxic pollutants), require continuous emissions monitors for PM, and tighten Hg limits for power plants that burn lignite coal. The commenters said that requiring that all plants monitor these fPM emissions with CEMS will ensure that the goals of these measures are met. They said that as proposed, by 2035 the new standard would cut pollution and protect people from:

- 82 pounds of Hg;
- 800 tons of $PM_{2.5}$;
- 8,800 tons of SO_2;
- 8,700 tons of NO_x; and
- 5 million tons of CO_2

The commenters stated that cleaning up Hg and other air toxics is projected to lead to $170 to $220 million in annualized health benefits and a further $170 million in annualized climate co-benefits. They said that strengthening the standards is cost-reasonable, technically feasible, legally required, and necessary to adequately protect public health and welfare.

The commenters said that strengthening the MATS to further reduce toxic emissions from coal- and oil-fired power plants is consistent with the EPA's role as a signatory to the Chesapeake Bay Agreement and Congress's clear directive in section 117(g) of the Clean Water Act.

Response 1: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

Comment 2: The commenters stated that American Indians and Alaska Native Villagers are reliant on natural food supplies including fish, game, and native plants and that nutritious foods are crucial components to the ecosystems that have sustained life for thousands of years. They said that Hg contamination of Tribal environments including fish, shellfish and other essential food supplies injects this potent neurotoxin into our vulnerable population. They said they support the proposed reduction of allowable Hg emissions from lignite-burning EGUs and enhanced emissions monitoring from all coal-fired and oil-fired EGUs.

Response 2: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

Comment 3: The commenters stated that as noted in the Fact Sheet accompanying the proposed regulation, "…the proposed rule is one part of a broader suite of actions that Administrator Regan announced in March 2022 to protect communities across the nation from the various health and environmental impacts of power plant pollution." They said that in addition to Hg and other air toxins from coal-fired and oil-fired EGUs, this industrial sector is a primary source of GHGs. The commenters said that the acute and continuous impacts of climate change on Native

Americans and Alaska Native Villagers are well documented but unfortunately, new consequences of this global crisis continue to be revealed. They said that for multiple reasons including vulnerability and geographic constraints Tribal communities are disproportionately suffering from these changes. The commenters said that the U.S. Fourth National Climate Assessment (NCA4 - *USGCRP, 2018: Impacts, Risks, and Adaptation in the United States*) noted, in part, that "Climate change increasingly threatens indigenous communities' livelihoods, economies, health, and cultural identities by disrupting interconnected social, physical, and ecological systems." A more focused examination of Tribal needs to address the impacts of climate change is presented in 2021 publication The Status of Tribes and Climate Change (*The Status of Tribes and Climate Change (STACC)*, Institute for Tribal Environmental Professionals, 2021).

The commenters said they have a long history of information sharing with the EPA and advocacy for reducing emissions of GHGs including *Status of Tribal Air Report* (National Tribal Air Association 2022) report which documents climate change impacts on Tribal lands and people. They said that the ravages of climate change continue to be of the utmost concern, and they support this proposed regulation as one part of the efforts to reduce reliance on coal-fired and oil-fired EGUs.

Response 3: The comment supports the conclusions in the proposed rule that the EPA is finalizing. For this reason, the comment requires no response.

Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR

Technical Memo

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

Final Rule

Docket ID No. EPA-HQ-OAR-2023-0072

U.S. Environmental Protection Agency

Office of Air and Radiation

April 2024

This document supports the EPA's Final New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units and the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units ("111 EGU Rules"). It describes projected resource adequacy impacts of the final 111 EGU Rules in conjunction with several other recently or nearly finalized EPA rulemakings: the LDV, HDV and MDV (collectively "Vehicle Rules"), Final 111 EGU Rules, ELG and MATS RTR (collectively "Power Sector Rules")[1]. **In doing so, it also demonstrates that the impacts of both the 111 EGU Rules alone and combined with other recent EPA actions related to electricity generating units are projected to result in anticipated power grid changes that (1) remain within the confines of key North American Electric Reliability Corporation (NERC) assumptions, (2) are consistent with peer reviewed projections for the power sector, and (3) are consistent with goals, planning efforts and Integrated Resource Plans (IRPs) of industry itself.[2,3] We project that the 111 EGU Rules, whether alone or combined with other Rules, are unlikely to adversely affect resource adequacy.**

This technical memo describes EPA's analysis of the potential impacts of the "Power Sector Rules" on the resource adequacy of the U.S. power grid. To best evaluate the impact of the Power Sector Rules on the power grid, the analysis includes the impacts of EPA's Vehicle Rules on demand for electricity in all scenarios. The objective of this analysis is to provide

---

[1] As outlined in this document, the results of this analysis are based on specific model runs that capture the latest available information at the time of the analysis and cover the cumulative impacts of the power sector rulemakings described above. As such the specific results presented will not match the results presented as part of the record for the individual rulemakings.

[2] EPA actions considered here include final rules regulating the EGU sector at the time this analysis was performed, as well as several near final rules that commenters alleged could, in concert with the Vehicle Rules, negatively affect grid reliability and resource adequacy. These include the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generation Point Source Category ("ELG Rule"), New Source Performance Standards for GHG Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired EGUs ("111 EGU Rules");Rule"); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generation Point Source Category ("ELG Rule"); and National Emissions Standards for Hazardous Air Pollutants: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review ("MATS RTR Rule").

[3] Commenters also allege that certain other rules could affect the reliability of the power sector. We disagree. We did not see a need to consider these other rules in our quantitative analysis as these other rules do not regulate new or currently operational EGUs. Furthermore, commenters failed to explain how these other rules nonetheless would significantly impact the power sector and adversely affect resource adequacy or grid reliability. Specifically, on May 19, 2023, EPA proposed changes to the Coal Combustion Residual (CCR) regulations for inactive surface compounds at inactive electric generating units. 88 FR 31982. As these units are no longer operating and providing electricity to the grid, that proposal is not part of this assessment. Additionally, EPA also proposed to establish groundwater monitoring, corrective action, closure, and post closure care requirements for all CCR management units and allowed for a deferral of closure for all CCR management units (including OAF) if those units are above critical infrastructure. These components did not change EPA's need to incorporate the legacy/CCRMU rule into its cumulative impacts analysis because the CCR rule is not expected to impact current utility operations. The EPA finalized the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter (PM NAAQS) on Feb. 7, 2024. The PM NAAQS rule itself does not regulate EGUs. It is also not possible to predict now what areas will be designated nonattainment for the PM NAAQS or what emissions control strategies states will adopt to attain and maintain the PM NAAQS, and EPA declines to speculate on how States might exercise their discretion. Further, the Administrator signed on Nov. 30, 2023, the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. This rule also does not regulate EGUs.

insight into the cumulative impacts on resource adequacy from EPA's rulemakings. EPA's role in regulating emissions from electric generating units does not include specifying generation resource mixes or grid operations and planning practices. Thus, EPA does not conduct operational reliability studies. Rather, in this document, EPA describes its modeling of the projected impact of the Vehicle and Power Sector Rules. The analysis includes both modeling of the power sector under reliability-protective constraints used by North American Electric Reliability Corporation (NERC) and additional non-modeling considerations related to resource adequacy. EPA finds that projected impacts to the resource mix are relatively modest, and that strong institutional mechanisms exist to preserve resource adequacy.

Resource Adequacy in the Context of EPA's Final Rules

Resource adequacy is an important aspect of grid reliability.[4] As used here, the term resource adequacy is defined as the provision for adequate generating resources to meet projected load and generating reserve requirements in a power region.[5] Another key aspect of reliability is operational reliability, which includes the ability to withstand sudden electric system disturbances that can lead to blackouts.[6] This document is meant to serve as a resource adequacy assessment of the cumulative impacts of the Power Sector Rules and how projected outcomes under the Power Sector Rules compare with projected baseline outcomes in the presence of the Inflation Reduction Act (IRA) and the Vehicle Rules. In the baseline, the impacts of the IRA result in an acceleration of the ongoing shift towards lower emitting generation and a declining share for fossil-fuel fired generation. Studies such as the *Electricity Sector Emissions Impacts of the Inflation Reduction Act* demonstrate that EPA's projected outcomes – inclusive of the IRA and Power Sector and Vehicle Rules - remain consistent with a range of peer-reviewed forecasts.[7]

Numerous additional national laboratory, academic, and industry-led studies have explored the resource adequacy impact of increasing clean electricity generation and decreasing power sector greenhouse gas emissions. Collectively, these studies demonstrate that meeting resource adequacy needs is achievable with current institutional mechanisms and known operational practices, under scenarios similar to and beyond those expected due to IRA and these rulemakings. While this document is limited to an analysis of resource adequacy within the context of these rulemakings, EPA notes that many of these studies have also demonstrated how reliability more generally can continue to be maintained under scenarios with significantly reduced levels of power sector greenhouse gas emissions. Collectively, these studies find that: resource adequacy can be maintained during all hours of the year through a portfolio approach that aggregates deployment of variable renewable resources with dispatchable resources, energy storage, and other technologies.[8] Beyond resource adequacy, these studies also evaluate operational reliability, finding that short-term variability and uncertainty in renewable generation can be cost effectively managed by increasing grid flexibility; increased utilization of power

---

[4] For additional discussion of reliability, see https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf.
[5] As analyzed in this document, power regions correspond to aggregates of Integrated Planning Model (IPM) regions corresponding to NERC assessment areas.
[6] https://www.ferc.gov/reliability-explainer
[7] Available at https://www.epa.gov/inflation-reduction-act/electric-sector-emissions-impacts-inflation-reduction-act.
[8] *Maintaining Grid Reliability – Lessons from Renewable Integration Studies.* National Renewable Energy Laboratory, April 2024. Available at: https://www.nrel.gov/docs/fy24osti/89166.pdf.

electronics can support frequency stability; and expanded transmission networks can help maintain and enhance reliability. Other studies have also evaluated highly decarbonized systems ability to maintain operational reliability in the face of supply disturbances or extreme demand circumstances. For example, in its filing before the Colorado Public Utilities Commission, Tri-State Electric Cooperative submitted a proposed resource mix that achieves an 89% reduction in greenhouse gas emissions by 2030, compared to 2005 levels, reached 70% zero-emission generation by 2030, and includes a new combined cycle unit with carbon capture and sequestration by 2031.[9] Tri-State included an analysis that tested its proposed resource mix against extreme weather events and found that the proposed portfolio can meet a very high standard of reliability even in extreme circumstances.[10]

Examples of these studies include National Renewable Energy Laboratory's (NREL) 100% renewable power system study (2021) using the Regional Energy Deployment System (ReEDS) model published in the journal *Joule* [11], and the Net-Zero America study (2021) from Princeton University, which uses the Energy PATHWAYS-Regional Investment and Operations (EP-RIO) model.[12] Both of these studies demonstrate how even higher levels of renewables can be part of a grid that maintains resource adequacy. The North American Renewable Integration Study (2021) found multiple pathways can lead to 80% power-sector carbon reduction continent-wide by 2050 while maintaining resource adequacy.[13] The Solar Futures Study (2021) found existing technology portfolio approaches could maintain resource adequacy under high solar deployment and decarbonization scenarios.[14] Examples of regional grid operator studies that examine how reliability can be maintained with a changing generation resource mix include ISO New England's Future Grid Reliability Study (2022)[15], Resource Adequacy in the Pacific Northwest (2019)[16], Energy Transition in PJM: Frameworks for Analysis (2021)[17], Midcontinent Independent System Operator's Renewable Integration Impact Assessment (2021)[18], and Southwest Power Pool's Wind Integration Study (2016)[19]. In addition, the U.S. Department of

---

[9] https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=1011533&p_session_id=

[10] Reliability metrics included achieving: 1) less than or equal to 3 loss of load hours per year, 2) less than or equal to 12 loss of load hours across the study period from 2026-2031, and 3) expected unserved energy cannot exceed 20% of load in any hour. Tri-State found that its preferred scenario achieves 0 MWhs of unserved energy and 0 hours of low of load in all years from its extreme weather sensitivity.

[11] Cole et al., Quantifying the challenge of reaching a 100% renewable energy power system for the United States. Joule 5, 1732–1748 July 21, 2021. https://doi.org/10.1016/j.joule.2021.05.011.

[12] Larson, E. et al., 2021. Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report Summary, Princeton University, Princeton, NJ. https://netzeroamerica.princeton.edu/the-report.

[13] https://www.nrel.gov/docs/fy21osti/79224.pdf

[14] https://www.energy.gov/sites/default/files/2021-09/Solar%20Futures%20Study.pdf

[15] *2021 Economic Study: Future Grid Reliability Study Phase 1.* ISO New England, July 2022. https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_future_grid_reliability_study_phase_1_report.pdf

[16] *Resource Adequacy in the Pacific Northwest.* Energy and Environmental Economics, Inc., March 2019. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

[17] *Energy in Transition in PJM: Frameworks for Analysis.* PJM Interconnection LLC, December 2021. https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx

[18] *MISO's Renewable Integration Impact Assessment*. MISO, February 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

[19] https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf

Energy (DOE) finds that a portfolio approach that takes advantage of the full range of technology, planning, and operational solutions best ensures reliable power.[20]

EPA's projected total load and variable renewable generation levels under this analysis[21] are comparable to the results of other studies which model the impacts of the IRA but not the Power Sector Rules as illustrated (see Figure 1). In this figure, the IPM horizontal line shows the projected total demand in the top panels together with the maximum projected share of variable renewable (solar and wind) generation in the bottom panels. IPM results shown are from EPA's cumulative impact assessment of its Power Sector and Vehicle Rules for 2030, 2035, 2040, and 2050. The multicolored points show the demand (top panels) and variable renewable share (bottom panels) from six other studies including single-model and multi-model studies of the electricity sector. Each of these other six studies present multiple loads and variable renewable shares resulting from different methods and assumptions. Two studies present results from multiple models and most report results from multiple scenarios. As evidenced in the figure, EPA's projected increase in demand and variable renewable share of generation incorporating the impacts of its Vehicle and Power Sector Rules (coupled with IRA and state policies) remains within the range and well below the upper bound of grid changes projected to be viable in other prominent models that respect resource adequacy constraints. The studies are approximately ordered from left to right in order of total load generation. **EPA finds its IPM projections align with the projections of other power sector models. Both the total projected demand and the projected variable renewable generation share are within the range of observed results from recent peer-reviewed research[22], reports from the Department of Energy[23] and the National Renewable Energy Laboratory.[24]** See Appendix Table H1 for details.

Figure 1: Cumulative IPM Demand and Variable Renewable (VR) Generation Projections Relative to Other Peer-reviewed Models (2030 - 2050)

[20] *The Future of Resource Adequacy.* DOE. 2024. https://www.energy.gov/policy/articles/new-doe-report-outlines-solutions-meet-increasing-electricity-demand-and-cut

[21] EPA Power Sector Rules do not require deployment of RE resources – these deployments are occuring based on the relative cost of these resources and the incentives afforded to them under the IRA.

[22] Bistline, J., et al., Emissions and energy impacts of the Inflation Reduction Act. Science, 2023. 380(6652): p. 1324-1327. DOI: 10.1126/science. adg3781. Available from: https://www.science.org/ doi/10.1126/science.adg3781

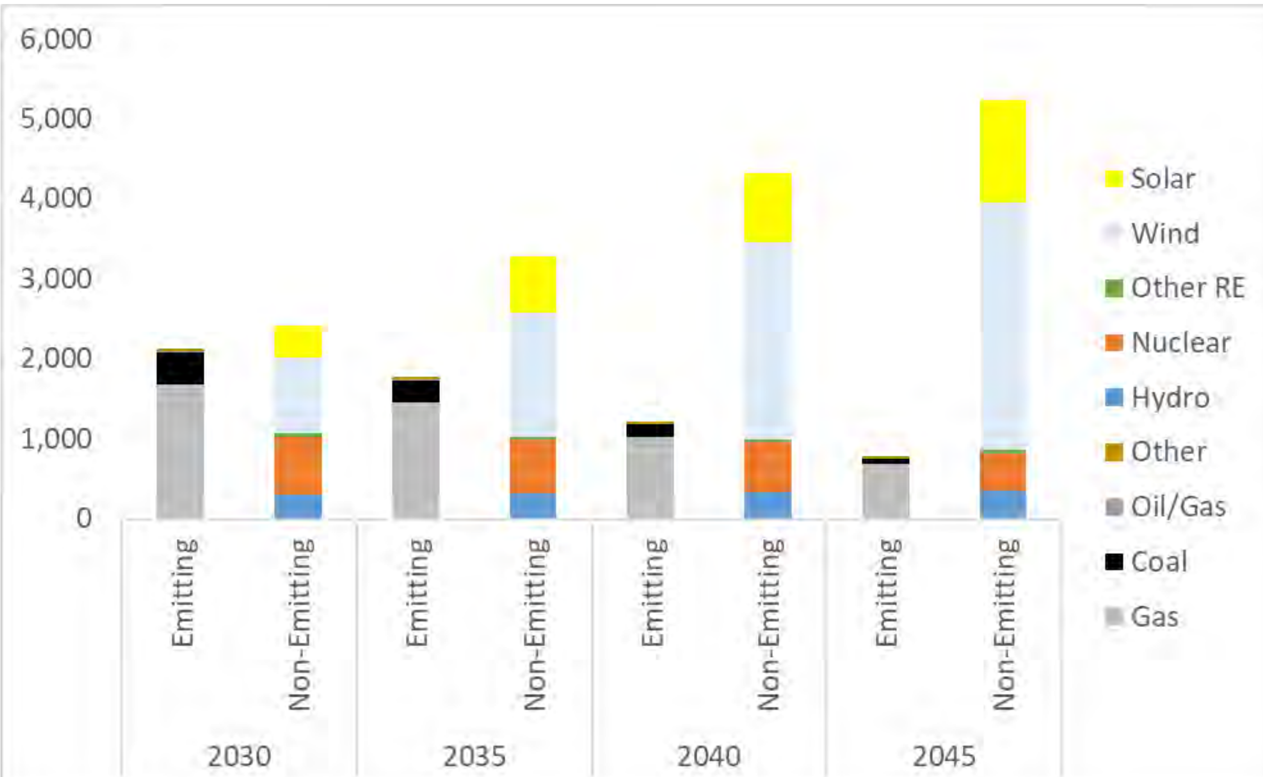
[23] U.S. Department of Energy, Investing in American Energy: Significant Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Energy Economy and Emissions Reductions. 2023. Available from: https://www.energy.gov/ policy/articles/investing-american-energy-significant-impacts-inflation-reduction-act-and

[24] Steinberg, D.C., et al., Evaluating impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. power system. 2023, National Renewable Energy Laboratory: Golden, CO. Available from: https://www.nrel.gov/docs/fy23osti/85242.pdf

The final 111 EGU Rules establish emissions rate limits for covered electric generating units (EGUs). The stringency of these emission rate limits is set through assuming the installation of various greenhouse gas (GHG) emissions control technologies. Covered sources would therefore be able to comply with the rules with these within-the-fence technologies and are not required to reduce utilization or shift generation. Nonetheless, given the flexibility provided by performance-based standards and in light of the transition of the power sector toward less emitting generating resources, as highlighted by stakeholders, it is anticipated that EGU owners and operators may also pursue alternative compliance strategies. Should those strategies involve the curtailment or retirement of existing generating resources or the operation of new generating resources at lower capacity factors than they would have otherwise, stakeholders have separately raised concerns that this could impact the reliability of the power grid.

EPA notes that—consistent with long- term industry trends—the amount of projected baseline coal-fired generation affected by these air regulations comprises a relatively small and decreasing portion of expected capacity and generation over the forecast period, which further limits any potential grid impacts and resource adequacy implications of the Power Sector Rules. Figure 2 highlights the coal share of overall generation in a future with the Vehicle Rules but without implementation of any Power Sector Rules. This generating category – which is the predominant source of generation facing pollution mitigation measures in the Power Sector Rules – constitutes a relatively small share of the baseline generation in future years between 2030 and 2045. The fact that the most significant mitigation measures are concentrated within a small portion of baseline generation inherently limits any potential grid impacts related from regulatory compliance. While the full change in generation composition is examined, only a small portion of that change in generation is attributable to the Power Sector Rules.

Figure 2. Baseline Case Projected Generation Mix in TWh (2030, 2035, 2040, 2045)



Note: As outlined above, the baseline includes additional electricity demand from the vehicle rules. Coal and Gas categories include generation from units that are projected to install CCS.

The emission reduction requirements under these 111 EGU Rules are based on adequately demonstrated cost-reasonable control measures that constitute the best system of emissions reduction (BSER). Some EGU owners may conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. EPA understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of any revenues necessary to compensate the EGU for the cost of continued operation until longer-term mitigation measures can be put in place. EPA expects that states will conduct meaningful engagement with relevant balancing authorities, grid operators, and reliability coordinators to promote early and informed reliability planning to ensure that electric system reliability is maintained during and after any resulting unit retirements.

While such potential impacts would not be a direct result of these rules but rather of the compliance choices source owners and operators may pursue, we have analyzed whether the projected effects of the rules would in this regard pose a risk to resource adequacy. It is important to recognize that the final 111 EGU Rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric system reliability. For more detail on how the final 111 EGU Rules address reliability concerns, see Section XII.F of the final 111 EGU Rule preamble. The results presented in this document show that the projected impacts of the final rules on power system operations, under conditions preserving resource adequacy, are relatively modest and manageable.

Methodology

The results presented in this document further demonstrate, for a specific set of cases illustrated in the IPM Sensitivity Analysis Memo – the "Sensitivity Vehicle Rules: Baseline" and "Sensitivity Vehicle Rules: Final 111 EGU Rules, MATS and ELG", that the implementation of these rules can be achieved without undermining resource adequacy. The focus of the analysis is on comparing the illustrative 111 EGU Final Rules scenario from the RIA in conjunction with other power sector rules to a base case without the power sector rules that is shown here to be consistent with other peer reviewed model projections. Both scenarios include the projected impacts of EPA's vehicle rules. Both cases also include existing legislation, such as the Inflation Reduction Act. Thus, this analysis focuses on the incremental changes in the power system that are projected specifically as a result of the Power Sector Rules. The EPA uses the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the power sector rules.[25] We evaluate the impacts of the rules in the 2028, 2030, 2035, 2040 and 2045 model run years.[26]

IPM is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and resource adequacy constraints. The EPA has used IPM for over two decades, including for prior successfully implemented rulemakings, to better understand power sector behavior under future business-as-usual

[25] See "IPM Sensitivity Runs – Memo", available in the docket for this rulemaking for more detail on the power sector impacts of the final rules.

[26] IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar years 2028-29 to run year 2028, calendar years 2030-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-41 to run year 2040 and calendar years 2042-47 to run year 2045. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs. The EPA relied on the same model platform at final rule as it did at proposal but made substantial updates to reflect public comments. Of particular relevance, the model framework relies on resource adequacy-related constraints that come directly from NERC. **This includes NERC target reserve margins, NERC Assessment regions, NERC Electricity Supply and Demand (ES&D) load factors, and NERC Generating Availability Data System. We note however that the targets and data collected by NERC do not reflect either mandatory reliability standards, tariff, or other obligations that registered entities are required to meet. The model projections for the power sector rules are showing compliance choices that occur in an environment that respects these NERC reliability considerations and constraints listed. These results are discussed in the body of this report and demonstrate, for the specific case illustrated in the RIA, that the implementation of the vehicle rules and power sector rules can be achieved without adversely affecting resource adequacy.**[27]

Consistent with real-world decision making by utilities, RTOs, and state regulators, IPM's least-cost dispatch solution, in concert with the model's capacity expansion decision-making framework, is designed to ensure resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits on the ability to transfer power between regions using the bulk power transmission system. Within each model region, IPM assumes that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region. The largest transmission constraints on the grid are represented in IPM using separate IPM regions, so each individual IPM region typically has relatively less internal transmission congestion (based on today's loads and resource mix).[28] Capacity expansion models often include transmission constraints only between selected regions (and not within them) because these models are designed to build out portfolios of generation resources and are not intended for detailed, local transmission planning.[29] While this analysis does not focus on local transmission availability, EPA notes that numerous federal actions are improving local transmission access

[27] In respect to these resource adequacy requirements, the estimate of the compliance cost of the regulation accounts for any investment cost used to satisfy these requirements. That is, the compliance cost estimate in the corresponding RIA for the regulations includes any incremental cost of the need to install capacity that is available for use consistent with these resource adequacy retirements. For example, if a regulation would require a plant to install a particular control, the model in the policy scenario would fully capture the cost of those investments in the total cost estimates of the policy.
[28] IPM models separate regions that tend to align with the zones that ISOs and RTOs use for resource adequacy planning. For example, MISO plans for resource adequacy using 10 resource adequacy zones in its Planning Resource Auction, and each is separately modeled by one or more regions in IPM.
[29] Boyd, Erin. Power Sector Modeling 101. U.S. Department of Energy. Available at: https://www.energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_021816_0.pdf

and interconnection processes.[30] The model also includes constraints that adjust the reserve margin contribution of renewable resources and storage as a function of generation fraction.[31] Additionally, IPM models operating reserves at the regional level, and can account for the impact of solar and wind on operating reserves requirements.[32] This document focuses on key regional results important to management of the power system. For a more complete presentation of the projected power sector impacts of these rules, see the "IPM Sensitivity Runs – Memo" available in the docket for this rulemaking.

In order to conduct this analysis, EPA began by updating the baseline used to conduct the RIA for the 111 EGU Rules to account for the projected incremental electricity demand from the recently finalized MDV, HDV and LDV rules (vehicle rules). The policy scenario includes the impacts of the vehicle rules as well, and adds in the requirements under the final 111 EGU rules, MATS RTR and ELG (Power Sector Rules).[33]

Non-modeling Considerations Related to Resource Adequacy

The electricity sector also has numerous additional tools to maintain resource adequacy and grid reliability that are often not captured in models. A recent DOE report outlines various technology tools available to meet resource adequacy needs, including new generation and storage, transmission expansion and enhancement, and demand side resources. Key technologies not often captured in models and not included explicitly in IPM but available to utilities in planning processes include: energy efficiency investments, deployment of virtual power plants leveraging distributed energy resources already being deployed, reconductoring existing transmission lines using advanced conductors, a suite of grid enhancing technologies like dynamic line ratings that can reduce congestion and help interconnect additional resources, deployment of energy storage at existing renewable energy generators, and re-use of existing infrastructure such as through powering non-powered dams.[34]

EPA notes that resource adequacy is typically a state prerogative, with different states having different mandates and structures to ensure system generation is sufficient to meet demand (including participation in regional resource adequacy constructs overseen by federally-regulated RTOs). Power companies, grid operators, and regulators have well-established, adaptive procedures and policies in place to preserve electric reliability in response to system changes. Grid operators administer adaptive programs, such as capacity markets and resource

[30] These actions include the following: FERC Order 2023 is streamlining interconnection of new generation resources to the transmission grid. FERC published a NOPR to address transmission planning and cost allocation challenges. DOE's Grid Resilience and Innovations Partnerships (GRIP) program has $10.5 billion to enhance grid flexibility and improve resilience. GRIP funding supports grid modernization and deployment of innovative transmission projects that accelerate interconnection of clean energy, among other objectives. The Transmission Facilitation Program (TFP) has a revolving $2.5 billion to overcome financial hurdles for new and upgraded transmission line development by allowing DOE to be an anchor customer for new transmission projects.

[31] For details, please see Chapter 4 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

[32] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling

[33] For details of policies modeled, please see Appendix section G.

[34] *The Future of Resource Adequacy.* DOE. 2024. https://www.energy.gov/policy/articles/new-doe-report-outlines-solutions-meet-increasing-electricity-demand-and-cut

adequacy programs, designed to require or incentivize medium- and long-term investment in the resources that will be needed to meet demand. In many states, regulators oversee long-term integrated resource planning by utilities to ensure that there is a diverse portfolio of generating resources with the qualities and attributes needed to reliably meet electricity demand. Integrated resource planning or an equivalent planning process is a critical tool available to states to help manage resource transitions. The Federal Energy Regulatory Commission (FERC), together with NERC and regional reliability organizations, establishes and enforces standards that transmission and generation utilities must meet to ensure operational reliability.

Over shorter time horizons, separate from mandatory reliability standards, grid operators and regulators have rules that require utilities to follow processes designed to protect reliability before making major plant modifications or retirement decisions. These typically include analysis of the potential impacts of retirement on reliability, identification of mitigating options, and, in some cases, temporary contracts to require operation until longer-term mitigation measures can be put in place. EPA has included compliance flexibilities in the final 111 EGU Rules that allow states, power companies, and grid operators to ensure grid reliability. These compliance flexibilities include clarifying the appropriate use of remaining useful life and other factors (RULOF) to address reliability issues during state plan development and in subsequent state plan revisions; allowing emission averaging, trading, and unit-specific mass-based compliance mechanisms; and, for certain mechanisms, including a backstop emission rate and offering a compliance date extension for affected EGUs that encounter unanticipated delays with control technology implementation. Additionally, EPA is finalizing two mechanisms, described in Section XII.F of the preamble for this rulemaking, to further address reliability concerns raised by commenters: a short-term reliability mechanism that allows affected EGUs to operate above their standard of performance for a limited time during periods of grid stress; and a reliability assurance mechanism to ensure sufficient firm capacity is available. In addition to these measures, the DOE has authority to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. The Vehicle Rules, discussed below, also have timing and compliance flexibilities that allow industry to meet the standards in a phased approach and through the technology mix of their choosing.

Overview of Resource Adequacy Impacts from the Vehicle Rules, 111, MATS RTR and ELG

The final 111 EGU Rules establish CO_2 emission rate limits on covered fossil fuel-fired power plants (electric generating units or EGUs) in the U.S. The EGUs covered by the rules and subject to these limits are certain existing fossil-fuel fired steam generating units with >25-megawatt (MW) capacity, and new, modified, and reconstructed stationary combustion turbine EGUs. For details on the definition of the covered sources and the derivation of these emission rates, please see sections VII, VIII, IX and X of the final rule preamble.

This analysis also includes the impacts of EPA's Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles – Phase 3 (HDP3) rule and the Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (LMDV) rule (collectively "Vehicle Rules"). The LMDV final rule establishes standards that will further reduce harmful air pollutant emissions from light-duty and medium-duty vehicles starting with model year 2027 and phasing in generally through model year 2032 and later. Similarly, the HDP3 final rule also establishes standards for model years (MYs) 2027 through 2032, building from the "Phase 2" greenhouse gas standards established in 2016. Both programs establish new standards that build upon EPA's previous regulations for federal emissions standards by setting more stringent performance-based emissions standards under which manufacturers choose the mix of vehicle and engine technologies to meet the standards given consumer preferences. The Vehicle Rule grid demands are based upon Alternative 3 from the proposed LMDV rule with the addition of heavy-duty vehicle charge demand based on an interim case for the HDP3 rule. We believe this analysis reasonably represents the projected effects of the final LDMV and HDP3 rules.[35] In addition, we note that the Vehicle Rules do not mandate manufacturers to follow specific technological pathways; to comply with the performance-based standards, manufacturers may pursue different technological pathways, for example with higher penetrations of clean internal combustion engine vehicles, that would result in significantly less electricity demand.

This analysis also reflects EPA's 2024 Effluent Limitation Guidelines, which strengthens the wastewater discharge standards that apply to coal-fired power plants, and the EPA's Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (MATS RTR) which strengthens and update the MATS for power plants to reflect recent developments in control technologies and the performance of these plants. See Appendix G for a description of the emissions limitations modeled to reflect each Power Sector Rule.

This analysis uses the same scenario and years of analysis contained in the RIA for the final 111 EGU rules.[36] The scenarios include a base case (with Vehicle Rules) and a second scenario with the final Power Sector Rules and the Vehicle Rules. For purposes of this resource adequacy assessment, estimates and projections are taken from those same scenarios and years as shown in the RIA for the 111 EGU rules (2028, 2030, 2035, 2040 and 2045).

In order to conduct this analysis, EPA began by updating the baseline used to conduct the RIA to account for the projected incremental electricity demand from the recently finalized MDV, HDV and LDV rules (vehicle rules). The policy scenario includes the impacts of the vehicle rules as well, and adds in the requirements under the final 111 EGU rules, MATS RTR and ELG (Power Sector Rules).[37]

Summary of Changes in Operational Capacity

---

[35] See LMDV RIA 5.1.1 for more information. Also, see Wood, E., B. Borlaug, K. McKenna, J. Keen, B. Liu, J. Sun, D. Narang, et al. 2024. *Multi-State Transportation Electrification Impact Study.* U.S. Department of Energy
[36] See Section 4 of the "Sensitivity IPM Runs – Memo" available in the docket for this rulemaking for descriptions of the other results projected under the scenarios examined.
[37] For details of policies modeled, please see Appendix section G.

Total operational capacity remains similar between the baseline and policy scenarios. Operational generating capacity[38] changes from the base case in 2028, 2030, 2035, 2040 and 2045 are summarized in Table 1 below.[39] In Table 1, the total operational nameplate capacity from all resources is shown for the base case in the top row and for the policy case that includes the Final 111 EGU Rules, MATS RTR, and ELG in the bottom row. The rows in between show the differences between the base case and policy case resource mixes in each year. The data is separated out by resource type and for retirements, de-rates, and additions.

[38] Operational capacity is any existing, new or retrofitted capacity that is not retired.

[39] This analysis is based on an updated IPM run (EPA's Power Sector Modeling Platform 2023 using IPM) which includes updated assumptions based on the latest available data including updates reflecting natural gas supply, RE cost and performance and demand. As such, the baseline results are not identical to those outlined in the earlier Vehicle Rule analysis.

Table 1. Operational Capacity Summary (2028, 2030, 2035, 2040, 2045)

Capacity (GW)	2028	2030	2035	2040	2045
Base Case Operational Capacity	1,378	1,431	1,737	2,139	2,570
Minus Cumulative Incremental Policy Case Retirements					
Coal	-9	-11	-24	-16	-21
Oil/Gas	2	1	5	5	5
Natural Gas Combined Cycle (NGCC)	0	0	0	0	0
Natural Gas Combustion Turbines (NGCT)	0	0	0	0	0
Nuclear	0	0	0	0	0
Minus Cumulative Incremental Policy Case Derates					
Coal	0	0	-4	-4	-4
Plus Cumulative Incremental Policy Case Additions					
NGCC	0	-1	-1	-3	-3
NGCT	1	4	12	14	22
Wind	15	16	16	7	10
Solar	2	5	5	7	11
Storage	0	-1	8	2	1
Other	0	1	1	0	0
Policy Case Operational Capacity	1,390	1,446	1,760	2,156	2,595

Since the model is designed to maintain adequate reserves in each region, projected retirements are offset by reliance on existing baseline excess reserves, incremental builds, and the ability to shift transmission flows between regions in response to changing generation mix. In 2035, the illustrative compliance scenario for the collective rules shows an incremental 24 GW of coal retirement, 5 GW fewer oil/gas steam retirements, 11 GW of incremental gas-fired additions, 16 GW of incremental wind additions, 5 GW of incremental solar additions, and 8 GW of incremental battery storage additions. The coal retirements are in addition to 79 GW of coal retirements by 2035 under the baseline. In summary, out of the roughly 1,740 GW of operational nameplate capacity in the vehicle rules baseline scenario in 2035, the illustrative compliance scenario for the collective rules shows replacement of 24 GW of coal capacity with 16 GW of gas and oil capacity and 30 GW of renewable and storage capacity. The incremental reduction in coal capacity represents 1.4 percent of total operational capacity of all types in 2035. The resulting resource mix meets all NERC reserve margins and other reliability requirements modeled in IPM, suggesting that the policy case resource mix meets resource adequacy requirements while complying with the final 111 EGU rules, MATS RTR, and ELG.

Planning Reserve Requirements

IPM uses a target reserve margin in each region[40] as the basis for determining how much capacity to keep operational in order to preserve resource adequacy. IPM retires capacity if it is no longer needed to provide energy for load nor to provide capacity to meet reserve margin during the planning horizon of the projections. Since current regional reserves may be higher than the target reserve margin for a region, IPM may retire reserve capacity if it is not economic to use it to maintain adequate reserve margins. Existing resources may also be more expensive, compared to alternatives such as building new capacity or transferring capacity from another region. As a result, some of the plants that are projected to retire will not need to be replaced. Because some existing plants eventually retire in most regions, and IPM builds no more than what it needs to maintain a target reserve margin in each region, the projected reserve margins tend to approach the target reserve margins over time. For details on projected reserve margins under the base and policy scenario, please see Appendix A-3, B-3, C-3, D-3, and E-3.[41]

Changes in Retirements and New Capacity Additions under the Final Power Sector Rules

The incremental retirements in the final rule case are shown above in Table 1 and are in addition to 79 GW of coal and 20 GW of oil/gas retirements already occurring in the baseline through 2035.

By 2035, the policy scenario as compared to the baseline leads to higher levels of overall existing coal retirements and new capacity additions (shown regionally in Table A5, B5 and C5). These retirements and additions in the projections are the result of the model's optimization of economic planning for energy and capacity needs; they do not represent required outcomes for any individual units, which will be able to consider multiple compliance options in response to the final rules. In particular, new additions in a base case scenario that do not occur in the policy scenario projections might, in reality, be retained under a policy if local reliability conditions rendered this development the most appropriate choice. These rules do not prevent generation owners from shifting retirements and additions among specific sources to ensure reliability in such circumstances.

Firm Capacity Transfers for Meeting Planning Reserve Requirements

In cases where it is economic to transfer planning reserves from a neighboring region, rather than supply reserves from within a region, IPM will transfer firm capacity, subject to summer and winter limits that are designed to ensure that these reserves can be transferred reliably. The transfer of reserves can occur, for example, if a region retires capacity that was used in the base case to meet reserve requirements, but a neighboring region has excess lower cost firm capacity that are not needed for its own reserve requirements. To examine these transfers, the EPA analyzed the change in net transfers from each region, where the net transfer for the base and policy cases is measured by the firm capacity sent to neighboring regions. In

[40] In IPM, reserve margins are used to represent the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived from reliability standards in NERC's electric reliability reports. The IPM regional reserve margins are imposed throughout the entire time horizon.
[41] See maps of IPM regions and NERC Assessment Regions, and the table of target and projected reserve margins in Appendix F. IPM regions are based on the regions NERC uses for regional assessments. These regions are used for the Appendix tables in this document.

these cases, a positive value signifies that the firm capacity sent to other regions is larger than the firm capacity received from other regions (sending and receiving regions can be different), while a negative value signifies that the capacity received is larger than the capacity sent. Thus, the value measures the degree to which resources in the region were reserved for use by other regions (positive value), or where the capacity to meet load in the region was served by resources in other regions (negative value). In each case these firm capacity transfers are limited within IPM by the firm Total Transfer Capabilities (TTC) between regions. Firm or Capacity TTCs represent the aggregate transmission transfer capability between two regions after a single contingency loss. Limiting firm capacity transfers to the Firm TTCs ensures that transferred capacity can continue to support resource adequacy even under contingency conditions. IPM further imposes joint transmission capacity limits that limit the cumulative firm capacity transferred between groups of model regions. These limits represent additional transmission system constraints that affect the maximum simultaneous transfer of capacity over multiple interfaces.[42]

To look at the projected impact of the policy case on transfers, the measure used was the change in the summer reserves sent in the policy case compared to the base case. To develop a relative measure of the impact of the policy, the change in reserves was measured as a percentage of load in the sending region. This percentage gives an indication of the significance of the policy for changes in the grid. In general, the percentage changes in the final power sector rules are below 2%, meaning that the modeled policy is projected to show little impact on any region's need to import capacity to maintain reserve margins. For details on projected transfers under the base and policy scenarios, please see Appendix A-6, B-6, C-6, D-6 and E-6.

[42] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

Appendix

Appendix A: Tables by IPM Region for Final Power Sector and Vehicle Rules in 2028 (Note: All Results Cumulative through Projection Year)

A1. Projected Operational Capacity in GW (2028)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,378	1,390	12	112	103	-8.9
ERCOT	179	181	2	6	4	-1.8
FRCC	69	69	0	4	3	-0.4
MISO	197	200	3	34	34	-0.5
ISONE	46	46	0	0	0	0.0
NYISO	53	53	0	0	0	0.0
PJM	232	232	-1	22	20	-2.3
SERC	178	179	1	20	17	-2.3
SPP	101	106	5	11	10	-1.5
WECC - non CAISO	220	221	1	16	16	0.0
CAISO	103	103	1	0	0	0.0

[a] Coal category does not include coal to gas conversions

A2. Summary of Summer Peak Loads and Reserve Capacity in GW (2028)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	805	805	933	932
ERCOT	73	73	86	86
FRCC	51	51	60	60
MISO	129	129	150	150
ISONE	25	25	27	27
NYISO	35	35	40	40
PJM	154	154	177	177
SERC	123	123	144	143
SPP	55	55	64	64
WECC - non CAISO	104	104	118	118
CAISO	56	56	66	66

A3. Summary of Target and Projected Reserve Margin % (2028)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		16%	16%	16%	0%
ERCOT	14%	18%	18%	4%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	17%	16%	1%	-1%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	14%	14%	1%	0%
CAISO	18%	18%	18%	0%	0%

A4. Policy Case Retired Capacity Incremental to Base Case in GW (2028)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	9.2	0.0	0.0	-2.2	7.0
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.4	0.0	0.0	0.0	0.4
MISO	0.0	0.5	0.0	0.0	-0.2	0.4
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	2.5	0.0	0.0	-0.7	1.9
SERC	0.0	2.3	0.0	0.0	-0.3	2.0
SPP	0.0	1.5	0.0	0.0	1.1	2.7
WECC - non CAISO	0.0	-0.1	0.0	0.0	0.0	-0.1
CAISO	0.0	0.0	0.0	0.0	0.0	0.0

A5. New Capacity in Policy Case Incremental to Base Case in GW (2028)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	0.4	1.2	15.4	2.4	-0.2	0.0	19.2
ERCOT	0.0	0.0	1.6	0.0	0.0	0.0	1.6
FRCC	0.0	0.1	0.0	0.0	0.3	0.0	0.4
MISO	-0.2	0.3	3.5	-0.1	0.0	0.0	3.5
ISONE	0.0	0.0	0.3	0.0	0.0	0.0	0.3
NYISO	0.0	0.0	0.0	0.0	0.1	0.0	0.1
PJM	1.1	0.0	0.0	0.0	-0.1	0.0	1.1
SERC	0.9	-0.2	2.4	0.0	0.0	0.0	3.1
SPP	0.0	0.0	4.9	2.4	0.0	0.0	7.4
WECC - non CAISO	-0.7	0.2	1.6	0.0	0.1	0.0	1.2
CAISO	-0.7	0.7	1.2	0.0	-0.6	0.0	0.5

A6. Net Reserves Sent by NERC Assessment Region in GW (2028)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-6.2	-5.9	0.3	0%
ERCOT	2.6	2.6	0.0	0%
FRCC	-2.7	-2.7	0.0	0%
MISO	-9.2	-9.0	0.2	0%
ISONE	1.4	1.7	0.2	1%
NYISO	-2.9	-2.8	0.1	0%
PJM	3.4	2.4	-1.0	-1%
SERC	5.2	6.0	0.8	1%
SPP	-1.3	-1.3	0.0	0%
WECC - non CAISO	3.8	4.2	0.4	0%
CAISO	-6.6	-7.0	-0.4	-1%

Appendix B: Tables by IPM Region for Final Power Sector and Vehicle Rules in 2030 (Note: All Results Cumulative through Projection Year)

B1. Projected Operational Capacity in GW (2030)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,431	1,445	14	95	84	-11.5
ERCOT	183	186	3	6	4	-1.8
FRCC	72	72	0	4	3	-0.4
MISO	206	212	6	26	24	-2.4
ISONE	50	50	0	0	0	0.0
NYISO	56	56	0	0	0	0.0
PJM	238	237	-1	21	17	-4.0
SERC	188	189	1	17	15	-1.7
SPP	105	109	4	11	9	-1.2
WECC - non CAISO	223	224	1	11	11	0.0
CAISO	110	110	0	0	0	0.0

[a] Coal category does not include coal to gas conversions

B2. Summary of Summer Peak Loads and Reserve Capacity in GW (2030)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	825	825	952	952
ERCOT	74	74	86	86
FRCC	53	53	63	63
MISO	132	132	153	153
ISONE	25	25	28	28
NYISO	36	36	41	41
PJM	158	158	181	181
SERC	127	127	146	146
SPP	56	56	65	65
WECC - non CAISO	107	107	121	121
CAISO	58	58	68	68

B3. Summary of Target and Projected Reserve Margin % (2030)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
ERCOT	14%	17%	17%	3%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

B4. Policy Case Retired Capacity Incremental to Base Case in GW (2030)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	11.3	0.0	0.0	-1.5	9.8
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.4	0.0	0.0	0.0	0.4
MISO	0.0	1.9	0.0	0.0	0.0	1.9
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	4.2	0.0	0.0	-0.7	3.5
SERC	0.0	1.7	0.0	0.0	0.2	1.9
SPP	0.0	1.2	0.0	0.0	1.1	2.4
WECC - non CAISO	0.0	0.0	0.0	0.0	0.0	0.0
CAISO	0.0	0.0	0.0	0.0	0.0	0.0

B5. New Capacity in Policy Case Incremental to Base Case in GW (2030)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-0.7	4.0	16.1	5.3	-1.3	0.9	24.3
ERCOT	0.0	0.0	2.3	0.0	0.0	0.0	2.3
FRCC	0.0	0.1	0.0	0.0	0.3	0.0	0.4
MISO	-1.4	1.3	5.2	2.9	-0.3	0.8	8.5
ISONE	0.0	0.0	0.1	0.0	0.0	0.0	0.1
NYISO	0.0	0.0	-0.1	0.0	0.0	0.0	-0.1
PJM	1.1	1.0	0.2	0.0	0.0	0.0	2.3
SERC	0.9	0.2	1.5	0.0	0.0	0.0	2.6
SPP	0.0	0.0	4.0	2.4	0.0	0.0	6.4
WECC - non CAISO	-0.6	0.6	1.1	0.0	0.1	0.0	1.2
CAISO	-0.7	0.7	1.8	0.0	-1.4	0.0	0.4

B6. Net Reserves Sent by NERC Assessment Region in GW (2030)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-6.1	-6.0	0.1	0%
ERCOT	2.6	2.6	0.0	0%
FRCC	-2.7	-2.7	0.0	0%
MISO	-12.0	-10.0	2.0	2%
ISONE	1.9	2.0	0.1	0%
NYISO	-3.3	-3.4	-0.1	0%
PJM	1.5	0.0	-1.5	-1%
SERC	8.5	8.6	0.1	0%
SPP	0.3	-0.2	-0.6	-1%
WECC - non CAISO	0.8	1.4	0.6	1%
CAISO	-3.7	-4.3	-0.6	-1%

Appendix C: Tables by IPM Region for Final Power Sector and Vehicle Rules in 2035
(Note: All Results Cumulative through Projection Year)

C1. Projected Operational Capacity in GW (2035)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,737	1,756	18	67	39	-28
ERCOT	205	204	-1	5	3	-2
FRCC	89	89	0	1	1	-1
MISO	265	272	7	19	14	-5
ISONE	60	60	0	0	0	0
NYISO	70	70	0	0	0	0
PJM	284	288	5	18	6	-12
SERC	229	229	0	10	7	-3
SPP	130	134	4	6	3	-3
WECC - non CAISO	262	265	3	8	6	-2
CAISO	144	145	1	0	0	0

[a] Coal category does not include coal to gas conversions

C2. Summary of Summer Peak Loads and Reserve Capacity in GW (2035)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	896	896	1,032	1,032
ERCOT	79	79	90	90
FRCC	58	58	68	68
MISO	142	142	166	166
ISONE	29	29	32	32
NYISO	38	38	43	43
PJM	167	167	192	192
SERC	136	136	156	156
SPP	60	60	69	69
WECC - non CAISO	123	123	139	139
CAISO	65	65	76	76

C3. Summary of Target and Projected Reserve Margin % (2035)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

C4. Policy Case Retired Capacity Incremental to Base Case in GW (2035)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	24.5	0.0	0.0	-5.4	19.0
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	4.2	0.0	0.0	-0.1	4.0
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	12.0	0.0	0.0	-0.7	11.3
SERC	0.0	2.0	0.0	0.0	-0.1	1.9
SPP	0.0	3.0	0.0	0.0	-2.1	0.9
WECC - non CAISO	0.0	0.9	0.0	0.0	-0.4	0.6
CAISO	0.0	0.1	0.0	0.0	0.0	0.1

C5. New Capacity in Policy Case Incremental to Base Case in GW (2035)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-0.8	11.7	16.3	5.3	8.3	0.9	41.6
ERCOT	0.0	0.1	-0.7	0.0	0.0	0.0	-0.7
FRCC	0.0	0.1	0.0	0.0	0.0	0.0	0.1
MISO	-1.4	4.5	7.3	-2.1	3.0	0.8	12.1
ISONE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM	1.1	5.0	5.9	2.1	2.5	0.0	16.6
SERC	0.9	0.2	-1.3	0.9	1.9	0.1	2.7
SPP	0.0	0.0	2.7	2.0	0.0	0.0	4.7
WECC - non CAISO	-0.7	1.1	2.4	1.6	0.4	0.0	4.8
CAISO	-0.7	0.7	0.0	0.7	0.5	0.0	1.2

C6. Net Reserves Sent by NERC Assessment Region in GW (2035)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-7.3	-7.4	-0.1	0%
ERCOT	-0.9	-0.9	0.0	0%
FRCC	-1.9	-2.3	-0.4	-1%
MISO	-7.3	-5.0	2.3	2%
ISONE	-1.1	-1.1	0.0	0%
NYISO	-2.5	-2.5	0.0	0%
PJM	0.7	-1.0	-1.8	-1%
SERC	6.4	6.2	-0.2	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-1.2	-1.6	-0.4	0%
CAISO	-1.7	-1.2	0.4	1%

Appendix D: Tables by IPM Region for Final Power Sector and Vehicle Rules in 2040 (Note: All Results Cumulative through Projection Year)

D1. Projected Operational Capacity in GW (2040)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	2,139	2,152	13	57	37	-20
ERCOT	236	236	-1	5	3	-2
FRCC	109	110	1	1	1	-1
MISO	348	349	1	19	13	-5
ISONE	76	76	0	0	0	0
NYISO	91	91	0	0	0	0
PJM	358	360	2	11	6	-5
SERC	292	294	2	9	7	-2
SPP	146	148	2	6	3	-3
WECC - non CAISO	311	317	7	5	3	-2
CAISO	171	171	0	0	0	0

[a] Coal category does not include coal to gas conversions

D2. Summary of Summer Peak Loads and Reserve Capacity in GW (2040)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	976	976	1,124	1,124
ERCOT	87	87	99	99
FRCC	63	63	75	75
MISO	152	152	178	178
ISONE	32	32	36	36
NYISO	42	42	48	48
PJM	179	179	205	205
SERC	146	146	168	168
SPP	65	65	75	75
WECC - non CAISO	136	136	154	154
CAISO	73	73	86	86

D3. Summary of Target and Projected Reserve Margin % (2040)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

D4. Policy Case Retired Capacity Incremental to Base Case in GW (2040)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	15.6	0.0	0.0	-5.1	10.5
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	4.4	0.0	0.0	-0.1	4.3
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	4.2	0.0	0.0	-0.7	3.6
SERC	0.0	1.2	0.0	0.0	-0.1	1.1
SPP	0.0	3.0	0.0	0.0	-2.1	0.9
WECC - non CAISO	0.0	0.4	0.0	0.0	0.0	0.4
CAISO	0.0	0.1	0.0	0.0	0.0	0.1

D5. New Capacity in Policy Case Incremental to Base Case in GW (2040)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-3.0	14.2	6.8	7.4	2.1	0.0	27.5
ERCOT	0.0	0.1	-0.9	0.0	0.0	0.0	-0.8
FRCC	-1.9	2.5	0.0	0.5	0.0	0.0	1.1
MISO	-1.4	5.9	0.3	-0.1	0.8	0.0	5.6
ISONE	0.0	0.0	-0.1	0.1	0.0	0.0	0.1
NYISO	0.0	-0.2	0.1	-0.5	0.2	0.0	-0.4
PJM	1.1	2.4	1.8	0.7	0.2	0.0	6.2
SERC	0.9	0.0	-0.4	2.5	0.9	0.0	3.9
SPP	0.0	0.0	1.4	1.6	0.0	0.0	3.1
WECC - non CAISO	-1.0	2.9	4.5	2.5	-0.4	0.0	8.6
CAISO	-0.7	0.7	0.0	-0.1	0.3	0.0	0.2

D6. Net Reserves Sent by NERC Assessment Region in GW (2040)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-6.2	-6.2	-0.1	0%
ERCOT	-0.8	-0.9	0.0	0%
FRCC	-3.5	-3.4	0.1	0%
MISO	-2.7	-2.4	0.3	0%
ISONE	-2.1	-2.1	0.0	0%
NYISO	-2.2	-2.2	0.0	0%
PJM	-1.1	-1.2	-0.1	0%
SERC	7.1	6.8	-0.3	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-2.1	-2.2	-0.1	0%
CAISO	-0.7	-0.6	0.1	0%

Appendix E: Tables by IPM Region for Final Power Sector and Vehicle Rules in 2045
(Note: All Results Cumulative through Projection Year)

E1. Projected Operational Capacity in GW (2045)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	2,570	2,591	21	44	19	-25
ERCOT	268	269	1	5	2	-3
FRCC	148	148	0	1	0	-1
MISO	406	415	8	14	10	-4
ISONE	87	86	-1	0	0	0
NYISO	100	99	-1	0	0	0
PJM	428	428	0	10	3	-6
SERC	370	373	4	5	1	-4
SPP	174	177	3	5	2	-3
WECC - non CAISO	382	389	7	5	1	-4
CAISO	207	207	-1	0	0	0

[a] Coal category does not include coal to gas conversions

E2. Summary of Summer Peak Loads and Reserve Capacity in GW (2045)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	1,058	1,058	1,219	1,219
ERCOT	93	93	106	106
FRCC	69	69	81	81
MISO	163	163	190	190
ISONE	36	36	40	40
NYISO	45	45	52	52
PJM	193	193	222	222
SERC	158	158	182	182
SPP	70	70	81	81
WECC - non CAISO	151	151	171	171
CAISO	81	81	95	95

E3. Summary of Target and Projected Reserve Margin % (2045)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

E4. Policy Case Retired Capacity Incremental to Base Case in GW (2045)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	20.6	0.0	0.0	-5.1	15.5
ERCOT	0.0	2.3	0.0	0.0	-2.1	0.2
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	3.3	0.0	0.0	-0.1	3.2
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	5.9	0.0	0.0	-0.7	5.2
SERC	0.0	3.1	0.0	0.0	-0.1	3.0
SPP	0.0	3.2	0.0	0.0	-2.1	1.1
WECC - non CAISO	0.0	2.4	0.0	0.0	0.0	2.4
CAISO	0.0	0.0	0.0	0.0	0.0	0.0

E5. New Capacity in Policy Case Incremental to Base Case in GW (2045)

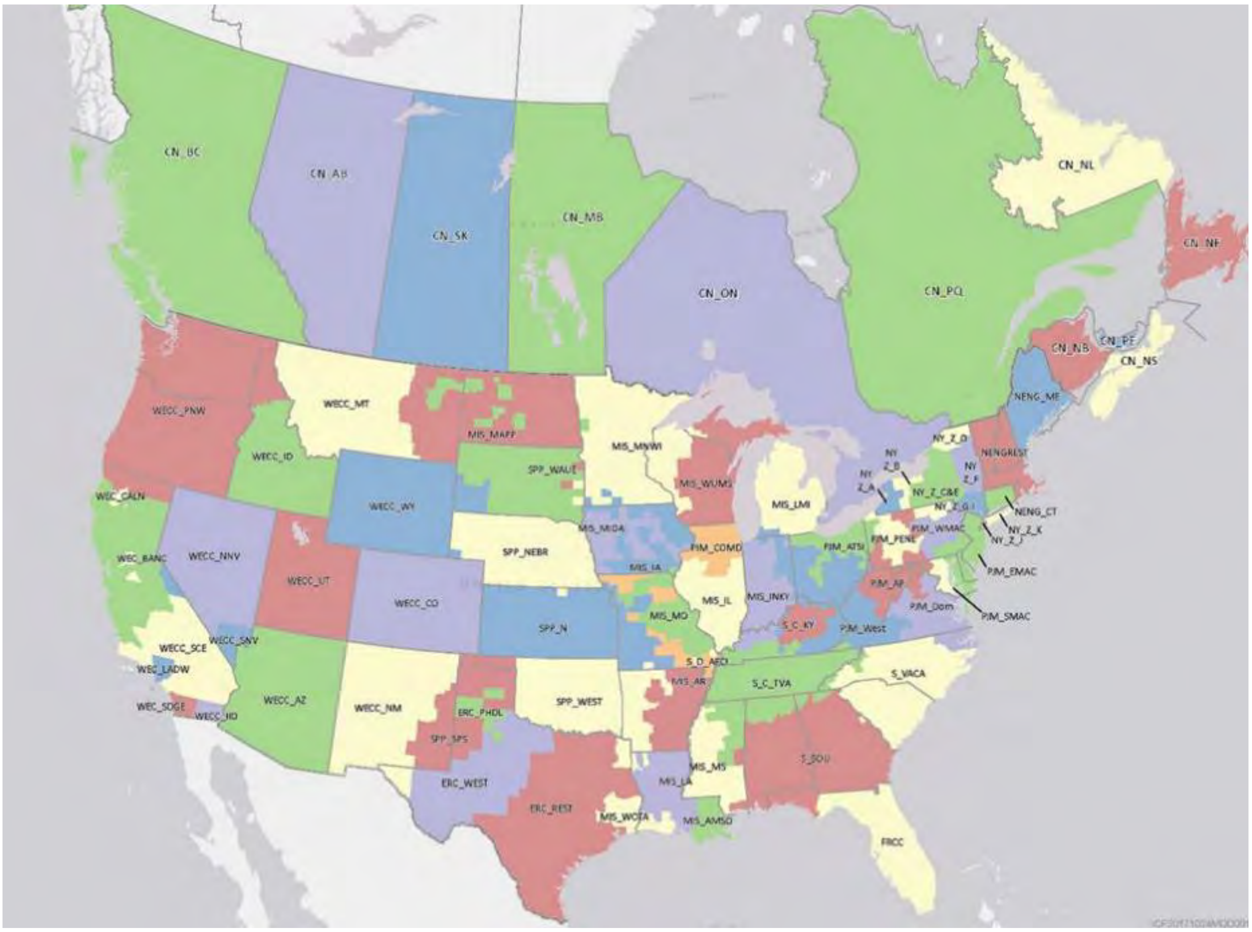
Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-3	22	10	11	1	0	41
ERCOT	0	1	-1	1	0	0	1
FRCC	-2	2	0	0	0	0	1
MISO	-1	5	7	1	0	0	12
ISONE	0	0	0	0	0	0	-1
NYISO	0	1	-1	-1	0	0	-1
PJM	1	5	0	1	0	0	6
SERC	1	2	0	4	1	0	8
SPP	0	1	3	1	0	0	5
WECC - non CAISO	-1	4	1	5	1	0	11
CAISO	-1	1	0	-1	0	0	-1

E6. Net Reserves Sent by NERC Assessment Region in GW (2045)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-5.9	-5.9	0.1	0%
ERCOT	-0.8	-0.8	0.0	0%
FRCC	0.0	0.0	0.0	0%
MISO	-5.2	-5.2	0.0	0%
ISONE	-2.8	-3.2	-0.4	-1%
NYISO	-1.9	-1.5	0.4	1%
PJM	-1.3	-1.2	0.1	0%
SERC	6.9	6.9	0.0	0%
SPP	2.1	2.1	0.0	0%
WECC - non CAISO	-2.0	-1.7	0.2	0%
CAISO	-0.9	-1.1	-0.2	0%

Appendix F: Maps

IPM v6 Map



Reporting Region Definitions:

Reporting Region	IPM Model Region
ERCOT	ERC_REST
ERCOT	ERC_WEST
ERCOT	ERC_PHDL
ERCOT	ERC_GWAY
ERCOT	ERC_FRNT
FRCC	FRCC
MISO	MIS_WOTA
MISO	MIS_AMSO
MISO	MIS_AR
MISO	MIS_MS
MISO	MIS_LA
MISO	MIS_MAPP
MISO	MIS_IA
MISO	MIS_MIDA
MISO	MIS_MNWI
MISO	MIS_IL

MISO	MIS_LMI
MISO	MIS_INKY
MISO	MIS_WUMS
MISO	MIS_MO
ISONE	NENG_CT
ISONE	NENGREST
ISONE	NENG_ME
NYISO	NY_Z_F
NYISO	NY_Z_K
NYISO	NY_Z_J
NYISO	NY_Z_C&E
NYISO	NY_Z_G-I
NYISO	NY_Z_D
NYISO	NY_Z_A
NYISO	NY_Z_B
PJM	PJM_COMD
PJM	PJM_EMAC
PJM	PJM_SMAC
PJM	PJM_WMAC
PJM	PJM_West
PJM	PJM_Dom
PJM	PJM_PENE
PJM	PJM_ATSI
PJM	PJM_AP
SERC	S_SOU
SERC	S_C_TVA
SERC	S_C_KY
SERC	S_VACA
SERC	S_D_AECI
SPP	SPP_N
SPP	SPP_NEBR
SPP	SPP_WEST
SPP	SPP_SPS
SPP	SPP_WAUE
SPP	SPP_KIAM
WECC - non CAISO	WECC_AZ
WECC - non CAISO	WEC_LADW
WECC - non CAISO	WECC_ID
WECC - non CAISO	WECC_PNW
WECC - non CAISO	WECC_CO
WECC - non CAISO	WECC_SNV
WECC - non CAISO	WECC_IID
WECC - non CAISO	WECC_NM
WECC - non CAISO	WECC_NNV
WECC - non CAISO	WECC_UT
WECC - non CAISO	WECC_MT
WECC - non CAISO	WECC_WY
WECC - non CAISO	WEC_BANC
CAISO	WEC_CALN
CAISO	WEC_SDGE
CAISO	WECC_SCE

F2: NERC Assessment Areas in Long Term Reliability Assessment.

Source: NERC 2022 Long-Term Reliability Assessment

G1: Modeled MATS RTR Requirements

Provision	Regulatory Option Modeled
FPM Standard (Surrogate Standard for Non-mercury HAP metals)	Revised fPM standard of 0.010 lb/MMBtu
Mercury Standard	Revised mercury standard for lignite-fired EGUs of 1.2 lb/TBtu
Continuous Emissions Monitoring Systems (PM CEMS)	Require installation of PM CEMS to demonstrate compliance

G2: Modeled ELG Requirements

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]
FGD Wastewater	NA (default unless in subcategory)[b]	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI
	Boilers permanently ceasing the combustion of coal by 2034	CP + Bio
	High FGD Flow Facilities or Low Utilization Boilers	NS
BA Transport Water	NA (default unless in subcategory)[b]	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI
	Boilers permanently ceasing the combustion of coal by 2034	HRR
	Low Utilization Boilers	NS
CRL	NA (default)[b]	ZLD
	Discharges of unmanaged CRL	CP
	Boilers permanently ceasing the combustion of coal by 2034	CP
Legacy wastewater	Operate after 2024	CP

Abbreviations: BMP = Best Management Practice; CP = Chemical Precipitation; HRR = High Recycle Rate Systems; SI = Surface Impoundment; ZLD = Zero Liquid Discharge; NS = Not subcategorized (default technology basis applies); NA = Not applicable

a. See TDD for a description of these technologies (U.S. EPA, 2024f).

b. The table does not present existing subcategories included in the 2015 and 2020 rules as EPA did not reopen the existing subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

Source: U.S. EPA Analysis, 2024

G3: Modeled Final Power Sector Rules Requirements

Summary of Modeled GHG Mitigation Measures for Existing Sources by Subcategory under the Illustrative Final Rules [a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035 but have committed to permanently ceasing operations by 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.
[c] Coal-fired EGUs that convert entirely to burn natural gas by 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

Summary of GHG Mitigation Measures for New Sources by Subcategory under the Illustrative Final Rules [a,b]

Affected EGUs	Subcategory Definition	Modeled Requirements During 1st Phase	Modeled Requirements During 2nd Phase (2035)	Baseload Definition: Final Rules Scenario
Baseload Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at greater than baseload annual capacity factor	Efficient generation	CCS or co-fire hydrogen at sufficient level to meet CCS emission rate	40%
Intermediate Load Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than baseload	Efficient generation		
Intermediate load Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of more than 40%	Emission rate consistent with NGCC operation		
Peaking Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 40%	Efficient generation		

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Delivered hydrogen price is assumed to be $1.15/kg in all years.

Appendix H:

Table H1: IPM Demand and Variable Renewable (VR) Generation Projections Relative to Peer-reviewed Studies

Source/Study	# of models / name	# scenarios reported	Type of Scenarios	2030 Total Demand (TWh)	2030 Share of VR Generation %
IPM	1 IPM	1	Described in the text of this memorandum	4,700	31%
Electricity Sector Impacts of IRA Study	14	1	IRA only	4,200 – 5,600	22% to 54%

National Climate Assessment Database	9	3	Reference, 2050 Net Zero CO_2, 2050 Net Zero CO_2 with advanced technologies	3,500 – 4,800	15% to 62%
Standard Scenarios 2023	1 ReEDS	53	Current Policies, 95% CO_2 Reduction by 2050, 100% CO_2 Reduction by 2035	4,400 – 5,200	45% to 58%
100% Renewable Study	1 ReEDS	7	Reference, 80%, 90%, 95%, 97%, 99%, 100%	4,200 – 4,700	22% to 81%
North American Renewable Integration Study	1 ReEDS	3	Reference, Medium Electrification, High Electrification	4,300 – 4,700	24% to 48%
Net-Zero America	1 EP-RIO	6	Reference, 100% Renewable, Renewable Constrained, High Biomass, Less-High Electrification, High Electrification	4,500 – 4,800	16% to 53%

Study	2035 Total Demand (TWh)	2035 Share of Variable Renewable Generation %	2040 Total Demand (TWh)	2040 Share of Variable Renewable Generation %	2050 Total Demand (TWh)	2050 Shareof VR Generation %
IPM	5,200	45%	5,700	59%	6,600	69%
Electricity Sector Impacts of IRA Study	4,200 – 6,300	21% to 80%	NA	NA	NA	NA
National Climate Assessment 5 Database	3,400 – 5.600	16% to 84%	3,800 – 6,700	15% to 86%	5,000 – 10,000	18% to 89%
Standard Scenarios 2023	4,700 – 7,300	51% to 74%	5,000 – 9,400	55% to 73%	5,600 – 12,300	56% to 76%
100% Renewable Study	4,400 – 5,300	24% to 82%	4,500 – 6,100	26% to 87%	5,000 – 7,500	35% to 90%
North American Renewable Integration Study	4,400 – 5,200	25% to 56%	4,600 – 5,900	27% to 64%	5,100 – 7,300	36% to 81%

Net-Zero America	4,700 – 6,200	19% to 75%	4,800 – 8,200	27% to 87%	5,300 – 16,000	38% to 98%

Note – TWh values for IPM here are rounded to nearest hundred for consistency when comparing across models.

Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule

EPA's Office of Air Quality Planning and Standards
Office of Air and Radiation
September 2019

Table of Contents

Index of Tables

Appendices

Index of Acronyms

AERMOD	American Meteorological Society/EPA Regulatory Model
AEGL	Acute exposure guideline level
ASTDR	US Agency for Toxic Substances and Disease Registry
CalEPA	California Environmental Agency
CTE	Central Tendency Estimate
ERPG	Emergency Response Planning Guideline
HAP	Hazardous Air Pollutant(s)
HEM	Human Exposure Model
HI	Hazard index
HQ	Hazard quotient
IRIS	Integrated Risk Information System
MACT	Maximum Achievable Control Technology
MIR	Maximum Individual Risk
MOA	Mode of action
NAC	National Advisory Committee
NAAQS	National Ambient Air Quality Standards
NATA	National Air Toxics Assessment
NEI	National Emissions Inventory
NPRM	Notice of Proposed Rulemaking
PB-HAP	Persistent and Bioaccumulative – HAP
PAH	Polycyclic aromatic hydrocarbon
POM	Polycyclic organic matter
REL	Reference exposure level
RfC	Reference concentration
RfD	Reference dose
RTR	Risk and Technology Review

TOSHI	Target-organ-specific hazard index
TRIM	Total Risk Integrated Methodology
TRIM.FaTE	TRIM Environmental Fate, Transport, and Ecological Exposure
URE	Unit risk estimate

Executive Summary

This document describes the risk assessment that the U.S. Environmental Protection Agency (EPA) conducted to assess the human health and environmental risks posed by hazardous air pollutant (HAP) emissions from coal- and oil-fired electric utility steam generating units (EGUs) regulated under the Mercury and Air Toxics Standards (MATS). Section 112 of the Clean Air Act (CAA) establishes a two-stage regulatory process for addressing emissions of HAP from stationary sources. In the first stage, EPA must promulgate technology-based national emission standards for hazardous air pollutants (NESHAP) for categories of sources. EPA has completed this stage. For NESHAP that require maximum achievable control technology (MACT) standards, EPA is required to complete a second stage of the regulatory process – the residual risk review. In this second stage, EPA is required to assess the health and environmental risks that remain after implementation of the standards. EPA must also review each of the technology-based standards at least every eight years and revise them, as necessary, taking into account developments in practices, processes and control technologies. If appropriate based on the results of the risk and technology reviews, the Agency will revise the rule. For efficiency, the Agency includes the analyses in the same regulatory package and calls the rulemakings the Risk and Technology Review (RTR).

The specific source category results contained in this document are from the coal- and oil-fired electric generating units (EGU) source category residual risk assessment, in support of EPA's 2020 final rule. The EPA is proposing amendments to the NESHAP for this source category, under 40 CFR part 63, subpart UUUUU, to address the results of the RTR review of the MACT standards, required under Section 112. This source category includes coal- and oil-fired EGUs regulated under the MATS. Pursuant to the CAA, an EGU is "any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale [is] considered an electric utility steam generating unit." Coal- and oil-fired EGUs are the largest anthropogenic source of mercury emissions in the U.S. and also the largest source of hydrochloric acid, hydrofluoric acid and selenium. EGUs are also a major source of metallic HAP including arsenic, chromium, nickel, and others. We estimate that there are 323[1] EGUs subject to the MATS operating in the U.S. The total emissions of HAP for the source category are approximately 5,100 tons per year. The HAP emitted in the largest quantities are hydrochloric acid, hydrofluoric acid, selenium compounds, manganese compounds, nickel compounds and chromium compounds. Emissions of these pollutants make up over 99 percent of the total HAP emissions by mass. Emissions of persistent and bioaccumulative HAP (PB-HAP) include lead compounds, arsenic compounds, mercury compounds, cadmium compounds, polycyclic organic matter (POM) and dioxins. Emissions of environmental HAP include the above PB-HAP plus hydrochloric acid and hydrofluoric acid.

---

[1] There are an estimated 323 facilities in the coal- and oil-fired EGU source category; however, one facility is located in Guam, which is beyond the geographic range of the model used to estimate risks. Therefore, the Guam facility was not modeled and the emissions for that facility are not included in this assessment.

The table below summarizes the results of the risk assessment for the Coal- and Oil-Fired EGU source category. Based on actual emissions, the estimated maximum lifetime individual cancer risk posed by the facilities is 9-in-1 million, with nickel compounds from oil fuel sources as the major contributor to the risk. The total estimated cancer incidence from this source category is 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 141,600,000 people live within 50 kilometers of the 322 modeled EGU facilities, and 193,000 people are estimated to have cancer risks at or above 1-in-1 million from HAP emitted from the facilities in this source category.

Risk Summary for the Coal- and Oil-Fired EGU source category

	Inhalation Cancer Risk		Population Cancer Risk			Max Chronic Individual Noncancer Risk		Max Acute Noncancer Risk		Multipathway Assessment
	Maximum Individual Risk (in 1 million)	Risk Driver	Cancer Incidence (cases per year)	≥ 10 in 1 million	≥ 1 in 1 million	Hazard Index (TOSHI)	Risk Driver	Hazard Quotient	Risk Driver	Risk Driver and Health Endpoints
Baseline Actual Emissions										
Source Category	9	nickel compounds	0.04	0	193,000	0.2 (respiratory)	nickel compounds, cobalt compounds	0.09	arsenic compounds	Cancer (arsenic)[a] Tier 3 screening value = 50; Noncancer (mercury)[b] site-specific HQ = 0.06
Whole Facility	9	nickel compounds	0.04	0	203,000	0.2 (respiratory)	nickel compounds, cobalt compounds	---	---	---
Baseline Allowable Emissions										
Source Category	10	nickel compounds	0.1	300	636,000	0.4 (respiratory)	nickel compounds, cobalt compounds	---	---	---

a. A Tier 3 multipathway screening analysis for the facility with the highest Tier 2 cancer screening value yielded a cancer screening value of 50-in-1 million for arsenic exposure for the gardener scenario.

b. Non-inhalation exposure to mercury emissions resulted in the highest noncancer screening values. We conducted a site-specific assessment of three MATS facilities located near McLean County, ND, which resulted in a hazard quotient (HQ) of 0.06 for mercury exposure for the fisher scenario.

Regarding the noncancer risk assessment, the estimated maximum chronic noncancer hazard index for the source category is 0.2 (for the respiratory hazard index) driven by emissions of nickel and cobalt compounds from oil fuel sources. Of the 141,600,000 people living within 50 kilometers of these facilities, no one is exposed to a noncancer hazard index above 1, based on actual emissions from sources regulated under this source category.

Regarding acute health risks posed by actual baseline emissions, the highest screening acute hazard quotient is 0.09 (based on an acute dose-response value for arsenic compounds). No facilities are estimated to have an acute hazard quotient greater than 1 for any of the acute dose-response values examined.

Whole facility (or "facility-wide") emissions include those regulated under this source category plus all other emissions generated at each facility. The results of the chronic inhalation cancer risk assessment based on whole facility emissions are more uncertain and rely on the quality of the emissions data collected for source categories outside this regulatory review. These emissions sources may not undergo the same level of data quality review as those being assessed in this regulatory assessment. The estimated maximum lifetime individual cancer risk posed by the 322 facilities, based on whole facility emissions, is 9-in-1 million with nickel compounds from oil fuel sources driving the risk. The total estimated cancer incidence based on whole facility emissions is 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 203,000 people are estimated to have cancer risks at or above 1-in-1 million from HAP emitted from all sources at the facilities in this source category. Regarding the noncancer risk assessment, the maximum chronic noncancer hazard index posed by whole facility emissions is estimated to be 0.2 (for the respiratory hazard index) driven by emissions of nickel and cobalt compounds from oil fuel sources. No one is exposed to a noncancer hazard index above 1, based on whole facility emissions from the 322 facilities within this source category.

Potential multipathway health risks under a fisher and gardener scenario were identified using a three-tier screening assessment of the PB-HAP emitted by facilities in this source category and a site-specific assessment using TRIM.FaTE. Of the 322 MATS facilities modeled, 307 facilities have reported emissions of carcinogenic PB-HAP (arsenic, dioxins and POM) that exceed a Tier 1 cancer screening value of 1, and 235 facilities have reported emissions of non-carcinogenic PB-HAP (mercury and cadmium) that exceed a Tier 1 noncancer screening value of 1. For facilities that exceeded a Tier 1 multipathway screening value of 1, we used additional facility site-specific information to perform an assessment through Tiers 2 and 3, as necessary, to determine the maximum chronic cancer and noncancer impacts for the source category. For cancer, the highest Tier 2 screening value was 200. This screening value was reduced to 50 after the plume rise stage of Tier 3. Because this screening value was much lower than 100-in-1 million, and because we expect the actual risk to be lower than the screening value (site-specific assessments typically lower estimates by an order of magnitude), we did not perform further assessment for cancer. For noncancer, the highest Tier 2 screening value was 30, with 4 facilities having screening values greater than 20. These screening values were reduced to 9 or lower after the plume rise stage of Tier 3. Because the final stage of Tier 3 (time-series) was unlikely to reduce the highest screening values to 1, we conducted a site-specific multipathway assessment of mercury emissions for this source category. The assessment took into account the effect multiple facilities within the source category may have on common lakes. The refined multipathway assessment estimated a hazard quotient of 0.06 for mercury for the 3 facilities assessed. This risk assessment represents the highest potential for mercury hazards through fish consumption for the source category.

In evaluating the potential multipathway risk from emissions of lead compounds, rather than developing a screening threshold emission rate, we compare maximum estimated chronic inhalation exposure concentrations to the level of the current National Ambient Air Quality Standard (NAAQS) for lead. Values below the level of the primary (health-based) lead NAAQS are considered to have a low potential for multipathway risk. We did not estimate any exceedances of the lead NAAQS in this source category.

We conducted an environmental risk screening assessment for the following pollutants: arsenic, cadmium, dioxins/furans, hydrochloric acid, hydrofluoric acid, lead, mercury (methyl mercury and mercuric chloride) and POMs. In the Tier 1 screening analysis for PB-HAP (other than lead, which was evaluated differently), POM emissions had no exceedances of any of the ecological benchmarks evaluated. Arsenic and dioxins/furans emissions had Tier 1 exceedances for surface soil benchmarks. Cadmium and methyl mercury emissions had Tier 1 exceedances for surface soil and fish benchmarks. Divalent mercury emissions had Tier 1 exceedances for sediment and surface soil benchmarks.

A Tier 2 screening analysis was performed for arsenic, cadmium, dioxins/furans, divalent mercury, and methyl mercury emissions. In the Tier 2 screening analysis, arsenic, cadmium, and dioxins/furans emissions had no exceedances of any of the ecological benchmarks evaluated. Divalent mercury emissions from two facilities exceeded the Tier 2 screen for a sediment threshold level benchmark by a maximum screening value of 2. Methyl mercury emissions from the same two facilities exceeded the Tier 2 screen for a fish (avian/piscivores) NOAEL (merganser) benchmark by a maximum screening value of 2. A Tier 3 screening assessment was performed to verify the existence of the lake associated with these screening values, and it was found to be located on-site and is a manmade industrial pond, and, therefore, it was removed from the assessment.

Methyl mercury emissions from two facilities exceeded the Tier 2 screen for a surface soil NOAEL for avian ground insectivores (woodcock) benchmark by a maximum screening value of 2. Other surface soil benchmarks for methyl mercury, such as the NOAEL for mammalian insectivores and the threshold level for the invertebrate community, were not exceeded. Given the low Tier 2 maximum screening value of 2 for methyl mercury, and the fact that only the most protective benchmark was exceeded, a Tier 3 environmental risk screen was not conducted for methyl mercury.

For lead, we did not estimate any exceedances of the secondary lead NAAQS. For HCl and HF, the average modeled concentration around each facility (i.e., the average concentration of all off-site data points in the modeling domain) did not exceed any ecological benchmark. In addition, each individual modeled concentration of HCl and HF (i.e., each off-site data point in the modeling domain) was below the ecological benchmarks for all facilities.
Based on the results of the environmental risk screening analysis, we do not expect an adverse environmental effect as a result of HAP emissions from this source category.

Finally, potential differences between actual emission levels and the maximum emissions allowed under EPA's standards (i.e., "allowable emissions") were also calculated for the facilities regulated under the MATS. Based on allowable emissions, the estimated maximum lifetime individual cancer risk is 10-in-1 million, with nickel compounds from oil fuel sources driving the cancer risks. The estimated maximum chronic noncancer hazard index is 0.4 (for the respiratory hazard index) based on allowable emissions, driven by nickel and cobalt emissions from oil fuel sources. The total estimated cancer incidence from this source category, considering allowable emissions, is 0.1 excess cancer cases per year, or one excess case in every 10 years. Based on allowable emissions, 636,000 people are estimated to have cancer risks at or above 1-in-1 million, with 300 of those people estimated to have cancer risks at or above above 10-in-1 million. No people are estimated to have a noncancer hazard index above 1.

This document summarizes the methods used to conduct the risk assessment of this source category as well as the results. Section 1 discusses the relevant regulatory framework including background on the Clean Air Act sections which require the EPA to conduct these source category risk assessments. Methods described in Section 2 include those used by EPA to develop refined estimates of chronic inhalation exposures and human health risks for cancer and noncancer endpoints, as well as those used to screen for acute health risks, chronic non-inhalation (i.e., multipathway) health risks, and adverse environmental effects. The source category-specific results for the risks are presented in Section 3. Section 4 contains a discussion of the uncertainties of the risk assessment, including uncertainties in the exposure assessment and in the dose-response values. The appendices to this risk report contain detailed descriptions of the methods used and the results.

1 Introduction

Section 112 of the Clean Air Act (CAA) establishes a two-stage regulatory process for addressing emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, section 112(d) requires the Environmental Protection Agency (EPA, or the Agency) to develop technology-based National Emission Standards for Hazardous Air Pollutants (NESHAP) for categories of sources (e.g., petroleum refineries, pulp and paper mills, etc.). EPA has completed this stage. For NESHAP that require maximum achievable control technology (MACT) standards, EPA is required to complete a second stage of the regulatory process – the residual risk review. In this second stage, EPA is required under section 112(f)(2) to assess the health and environmental risks that remain after implementation of the MACT standards. If additional risk reductions are necessary to protect public health with an ample margin of safety or to prevent an adverse environmental effect, EPA must develop standards to address these remaining risks. For each source category for which EPA issued MACT standards, the residual risk stage must be completed within eight years of promulgation of the initial technology-based standard.

Also, under section 112(d)(6), EPA must review each of the technology-based standards at least every eight years and revise it, as necessary, taking into account developments in practices, processes and control technologies. If appropriate based on the results of the risk and technology reviews, the Agency will revise the rule. For efficiency, the Agency includes the 112(f) and 112(d) analyses in the same regulatory package and calls the rulemakings the Risk and Technology Review (RTR).

In December 2006 we consulted with a panel from the EPA's Science Advisory Board (SAB) on the "Risk and Technology Review (RTR) Assessment Plan," and in June 2007 we received a letter with the results of that consultation. Subsequent to the consultation, in June 2009, EPA met with an SAB panel for a formal peer review of the "Risk and Technology Review (RTR) Assessment Methodologies" (USEPA, 2009a). We received the final SAB report on this review in May 2010 (USEPA, 2010a). Where appropriate, we responded to the SAB's key recommendations in developing our current risk assessments and continue our efforts to improve our assessments by incorporating updates that address the SAB's recommendations as they are developed and become available. Our responses to the key recommendations of the SAB are outlined in a memo entitled, "EPA's Actions in Response to Key

Recommendations from the SAB Review of RTR risk Assessment Methodologies" (USEPA, 2010b). EPA has updated several aspects of the risk assessment methodologies contained in the 2009 document. In 2017, we submitted these updated methodologies to SAB for review. The updated methodologies are described in, Screening Methodologies to Support Risk and Technology Reviews (RTR): A Case Study Analysis. The SAB's findings for this review were submitted to EPA in September, 2018.

This document contains the methods we use to conduct the risk assessment, the results of the residual risk assessment performed for the Coal- and Oil-fired EGU source category, and a description of associated uncertainties.

2 Methods

A risk assessment consists of four steps: 1) hazard identification, 2) dose-response assessment, 3) exposure assessment, and 4) risk characterization. The first step, hazard identification, determines whether the pollutants of concern can be linked to the health effects in question (cancer and/or noncancer). Section 112 of the CAA identifies the HAP to be considered in the risk assessment for this source category. The second step is the dose-response assessment, which quantifies the relationship between the dose of a pollutant and the resultant health effects. Dose-response assessments are performed by EPA through the Integrated Risk Information System (IRIS) process as well as by other agencies, such as the Agency for Toxic Substances and Disease Registry (ATSDR). See Section 2.7 of this document for more information on dose-response assessments. The third and fourth steps, the exposure assessment and the risk characterization, respectively, are specific to the source category and are described throughout this report. The exposure assessment includes characterization of HAP emissions, environmental fate and transport, and population exposure for both inhalation and non-inhalation pathways. The fourth and final step, risk characterization, integrates all the information from the previous steps and describes the outcome of the assessment. This four-step approach to risk assessment was endorsed by the National Academy of Sciences in its publication "Science and Judgment in Risk Assessment" (NAS, 1994) and subsequently was adopted in the EPA's "Residual Risk Report to Congress" (USEPA, 1999).

The EPA conducts a risk assessment that provides estimates of the maximum individual risk (MIR) posed by the HAP emissions from each source in the source category, the hazard index (HI) for chronic exposures to HAP with potential to cause chronic (or long-term) noncancer health effects and the hazard quotient (HQ) for acute exposures to HAP with the potential to cause acute (or short-term) noncancer health effects. The MIR is defined as the cancer risk associated with a lifetime of exposure at the highest concentration of HAP where people are likely to live. The HQ is the ratio of the potential exposure to the HAP to the level at or below which no adverse effects are expected; the HI is the sum of HQs for HAP that affect the same target organ or organ system. The risk assessment also provides estimates of the distribution of cancer risks within the exposed populations, cancer incidence and an evaluation of the potential for adverse environmental effects. The following sections describe how we estimate HAP emissions and conduct steps three and four of the risk assessment. The methods used to assess risks are consistent with those peer reviewed by a panel of the EPA's Science Advisory

Board (SAB) in 2009 and described in their peer review report issued in 2010 (USEPA 2010a).

2.1 Emissions and source data

To conduct the exposure assessment, EPA gathers the best available data on emissions, emissions release parameters, and other relevant source category-specific parameters. EPA determines the HAP emissions levels from emission points in the source category and identifies the emissions release characteristics of these emission points (e.g., stack height). EPA often begins with the National Emissions Inventory (NEI) database as the starting point for emissions and emissions release characteristics for the source category. The NEI database contains information about sources that emit HAP and it contains annual air pollutant emissions estimates. EPA's industry experts review the source category data for consistency and completeness. This includes an evaluation of facilities contained in the source category, the emissions units expected to be included for the processes in the source category, and the HAP compounds and emissions levels typically seen. If necessary, EPA will conduct a formal information collection request (CAA, Section 114) for emissions data and other data from the industry associated with the source category under review. Following the creation of the initial data set, the EPA performs the technology review and the residual risk assessment. If appropriate, based on the results of these reviews, the EPA proposes regulatory action for the source category in a Notice of Proposed Rulemaking (NPRM) published in a *Federal Register* notice. The NPRM data sets are available for public review in the rulemaking docket. Industry, state and local agencies, as well as the public have an opportunity to provide comments on the data, analyses, and results used to support the proposed action. EPA incorporates the comments, as appropriate, conducts any re-assessment, and summarizes and responds to comments before finalizing the action. Through source category-specific engineering reviews, information collection efforts, and public comment, EPA ensures that the data used to conduct risk assessments in support of the RTR rulemakings are of high quality.

In order to put the source category risks in context, we also examine the risks from the entire "facility," where the facility includes all HAP-emitting operations within a contiguous area and under common control. In other words, we examine the HAP emissions not only from the source category emission points of interest, but also from all other emission sources at the facility for which we have data. Using the most current available NEI data at the time of the assessment, the EPA develops "facility-wide" emissions estimates. It is important to note that the NEI facility-wide inventory may not always reflect the level of detail or be representative of the same temporal period that is found in the source category-specific inventory. Further information on the NEI, which is developed from federal/state/local/tribal submitted data, can be found on the EPA's web site at: https://www.epa.gov/air-emissions-inventories/national-emissions-inventory.

Details on the development of the source data, emissions, and associated uncertainties in the data for the Coal- and Oil-Fired EGU source category can be found in Appendix 1 (*Emissions Inventory Support Documents*). Section 3 provides a summary of the processes and emissions associated with this source category.

2.2 Dispersion modeling for inhalation exposure assessment

For the residual risk analyses, we estimate both long- and short-term inhalation exposure concentrations and associated health risks from each facility in the source category. To do this, we use the Human Exposure Model 3 (HEM-3 or HEM-AERMOD) modeling system – which combines the Human Exposure Model (HEM) with the American Meteorological Society/EPA Regulatory Model (AERMOD) dispersion modeling system. HEM-3 performs three main operations: atmospheric dispersion modeling, estimation of individual human exposures and health risks, and estimation of population risks. The approach used in applying this modeling system is outlined below. Further details are provided in Appendix 2 to this document (*Technical Support Document for HEM-3 Modeling*). This section focuses on the dispersion modeling component.

The dispersion model in the HEM-3 modeling system, AERMOD version 18081is a state-of-the-science Gaussian plume dispersion model that is preferred by EPA for modeling point, area, and volume sources of continuous air emissions from facility applications (USEPA, 2005a). Further details on AERMOD can be found in the AERMOD User's Guide (USEPA, 2018a) and the AERMOD Implementation Guide (USEPA, 2018b).[2] The model is used to develop annual average ambient concentrations through the simulation of hour-by-hour dispersion from the emission sources into the surrounding atmosphere. Unless data are available on the hours of operation for a source category, default hourly emission rates used for this simulation are generated by evenly dividing the total annual emission rate from the inventory into the 8,760 hours of the year.

The first step in the application of the HEM-3 modeling system is to predict ambient concentrations at locations of interest. The AERMOD model options employed are summarized in Table 2.2-1 and are discussed further below.

---

[2] An explanation of the updates from the previous version of AERMOD can be at https://www.epa.gov/scram/air-quality-dispersion-modeling-preferred-and-recommended-models#aermod and corresponding updates to HEM can be found at https://www.epa.gov/fera/human-exposure-model-hem-3-users-guides.

Table 2.2-1. AERMOD version 18081 Model Options for RTR Modeling

Modeling Option	*Selected Parameter for chronic exposure*
Type of calculations	Hourly Ambient Concentration
Source types	Point Volume Area Polygon Line Buoyant Line
Receptor orientation	Polar (13 rings and 16 radials) Discrete (census block centroids) and user-supplied receptors
Terrain characterization	Actual from USGS 1/3-arc-second DEM data
Building downwash	Not Included
Plume deposition/depletion	Not Included
Urban source option	Site Specific (See Appendix 2)
Meteorology	1-year representative NWS from nearest site (824 stations) for year 2016

In HEM-3, meteorological data are ordinarily selected from a list of more than 800 National Weather Service (NWS) surface observation stations across the continental United States, Alaska, Hawaii, and Puerto Rico, and HEM-3 defaults to the station closest to each modeled facility. We use data from other stations in special circumstances if we have reason to believe that other data are more representative for certain facilities. In this analysis, the average distance between a modeled facility and the respective meteorological station was 22 miles (35 km). The meteorological data in HEM-3's library are for a single year, and 2016 is the most recent full year of available data. EPA's Guideline on Air Quality Models addresses the regulatory application of air quality models for assessing criteria pollutants and requires five years of data to capture variability in weather patterns from year to year. We follow the guideline for air toxics modeling also; however, because dispersion model runtimes using five years of meteorological data would be too long for RTR source categories with many sources, we model only a single year. While the selection of a single year may result in under-prediction of long-term ambient levels at some locations, it may result in over-prediction at others. The sensitivity of model results to the selection of the nearest weather station and the use of one year of meteorological data is discussed in "Risk and Technology Review (RTR) Risk Assessment Methodologies" (USEPA 2009a).

We use the AERMET meteorological data preprocessor and the Automated Surface Observing System (ASOS) surface data and Forecast Systems Laboratory (FSL) upper air data to generate nationwide surface and profile files for input into AERMOD. In 2016, the Agency released to the public on the EPA's Support Center for Regulatory Atmospheric Modeling (SCRAM) website both AERMET and AERMOD (version 18081). Appendix 3 to this document (*Meteorological Data for HEM-3 Modeling*) provides a complete listing of meteorological stations and assumptions, along with further details used in processing the data through AERMET. EPA has posted the AERMET meteorological data (2016) used in this analysis on the EPA's Fate, Exposure, and Risk Analysis (FERA) website under the Human Exposure Model (HEM) page.

The HEM-3 modeling system estimates ambient concentrations at the geographic centroids of census blocks (using the 2010 Census) and at other receptor locations that can be specified by the user.[3] See Appendix 4 of this document (*Dispersion Model Receptor Revisions and Additions*) for a discussion of user receptors and centroid location changes specific to this source category. HEM-3 accounts for the effects of multiple facilities when estimating concentration impacts at each block centroid. We typically combine the impacts of all facilities within the same source category and assess chronic exposure and risk for all census blocks[4] with at least one resident (i.e., locations where people may reasonably be assumed to reside rather than receptor points at the fenceline of a facility). We then calculate ambient concentrations as the annual average of all estimated short-term (one-hour) concentrations at each block centroid. We do not consider possible future residential use of currently uninhabited areas.

To assess the potential impacts from short-term exposures, we estimate worst-case one-hour concentrations at the census block centroids and at points closer to the facility (using either the polar receptors or user-specified receptors) that represent locations where people may be present for short periods[5]. Note that this is in contrast to the development of ambient concentrations for evaluating long-term exposures, which we perform only for occupied census blocks. Since short-term emission rates are needed to screen for the potential for hazard via acute exposures, and since the emission data typically contain only annual emission totals, we generally apply the assumption to all source categories that the maximum one-hour emission rate from any source is ten times the average annual hourly emission rate for that source. However, sources may emit on a more intermittent basis and source category-specific data may support the use of engineering judgement to determine peak hourly emissions for any given process. Further information on the factor used to estimate short-term emissions for this source category is provided in Appendix 1, and further discussion of the acute risk assessment can be found in Section 2.4.

We determine census block elevations for HEM-3 nationally from the US Geological Survey 1/3 Arc Second National Elevation Dataset, which has a spatial resolution of about 10 meters. Each polar receptor is assigned the highest elevation of any census block in its neighborhood (all blocks closer to that polar receptor than any other polar receptor). If an elevation is not provided for an emission source, the model uses the average elevation of all polar receptors on the innermost polar ring. In addition to using receptor elevation to determine plume height, AERMOD adjusts the plume's flow if nearby elevated hills are expected to influence the wind

[3] We also estimate ambient concentrations for a grid of polar receptors that is specific to each facility, and these receptors are used to interpolate concentrations for census blocks in the outer part of the modeling domain, and for finding the maximum offsite concentrations.

[4] Census blocks, the finest resolution available in the census data, are typically comprised of approximately 50 people or about 20 households.

[5] Generally, we estimate these concentrations at locations no nearer than 100 meters from the center of the facility (note that for large facilities, this 100-meter ring could still contain locations inside the facility property).

patterns. For details on how hill heights are estimated and used in the AERMOD modeling, see Appendix 2 of this document.

2.3 Estimating chronic human inhalation exposure

We use the estimated annual average ambient air concentration of each HAP at each census block centroid or user-defined receptor as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The risk assessment does not consider either the short-term or long-term behavior (mobility) of the exposed populations and its potential influence on their exposure.

We do not address short-term human activity, including indoor air concentrations. Our experience with the National Air Toxics Assessment (NATA), which models daily human activity using EPA's HAPEM, suggests that given our current understanding of the ratio of exposure concentrations to ambient values, including short-term human activity in RTR analyses would, on average, reduce risk estimates by up to about 25 percent for particulate HAP and typically by much less for gaseous HAPs. To ensure the risk characterization is health protective, EPA risk assessors do not include this small potential reduction in exposure concentrations when calculating risks.

We do not address long-term migration or population growth or decrease over the 70-year modeling period. Instead, we assume that each person's predicted exposure is constant over the course of their lifetime, which is assumed to be 70 years. The assumption of not considering short- or long-term population mobility does not bias the estimate of the theoretical MIR (assumes a person stays in one location for 70 years) nor does it affect the estimate of cancer incidence since the total population number remains the same. It does, however, affect the shape of the distribution of individual risks across the affected population, shifting it toward higher estimated individual risks at the upper end and reducing the number of people estimated to be at lower risks, thereby increasing the estimated number of people at higher risk levels.

2.4 Acute risk screening and refined assessments

In establishing a scientifically defensible approach for the assessment of potential health risks due to acute exposures to HAP, we follow a similar approach to that for chronic health risk assessments under the residual risk program, in that we begin with a screening assessment and then, if appropriate, perform a refined assessment.

The approach for the acute health risk screening assessment is designed to eliminate from further consideration those facilities for which we have confidence that no acute adverse health effects of concern will occur. For this screening assessment, we use readily available data and conservative assumptions for emission rates, meteorology, and exposure location that, in combination, approximate a worst-case exposure.

The following are the steps we take and assumptions we make in the acute screening assessment:

- When available, we use peak 1-hour emission data obtained from data collection efforts or estimated based on the operating characteristics and engineering judgement of facility emission sources; otherwise, we use a default emission adjustment factor of 10 based on an analysis using a short-term emissions data set from a number of sources located in Texas (originally reported on by Allen *et al.* 2004) (see Appendix 5 of this document, *Analysis of Data on Short-term Emission Rates Relative to Long-term Emission Rates*).
- We assume that the peak emissions occur at all emission points at the same time.
- For facilities with multiple emission points, 1-hour concentrations at each receptor are assumed to be the sum of the maximum concentrations due to each emission point, regardless of whether those maximum concentrations occurred during the same hour.
- Worst-case meteorology (from one year of local meteorology) is assumed to occur at the same time the peak emission rates occur. The recommended EPA local-scale dispersion model, AERMOD, is used for simulating atmospheric dispersion.
- A person is assumed to be located downwind at the point of maximum modeled impact during this same worst-case 1-hour period, but no nearer to the source than 100 meters.

As a result of this screening assessment, the maximum HAP concentration is compared to multiple acute dose-response values for the HAP being assessed to determine whether a possible acute health risk might exist. The acute dose-response values are described in section 2.7.2 of this report.

A facility will either be found to pose no potential acute health risks (i.e., it will "screen out") or will need to undergo a more refined assessment. When we identify levels of a HAP that exceed its acute health benchmarks, we perform a more refined assessment, if possible. Situations in which we have used engineering judgement to estimate emissions, a refinement may be to obtain facility-specific data on HAP emissions. Other refinements may include the temporal pattern of emissions (number of working hours, batch vs continuous operation), the location of emission points, the boundaries of the facility, and/or the local meteorology. In some cases, all of these site-specific data are used to refine the assessment; in others, lesser amounts of site-specific data may be used to determine that acute exposures are not a concern, and significant additional data collection is not necessary. See Section 3 of this document for the approach used for this source category.

2.5 Multipathway human health risk assessment

Due to the potential for significant human health risks due to exposure via routes other than inhalation (e.g., ingestion), we determine whether any sources emit HAP known to be persistent and bioaccumulative in the environment (PB-HAP).[6] The set of PB-HAP

[6] Although the two-letter chemical symbol for lead is Pb, in this assessment PB-HAP refers to the many air pollutants known to be persistent and bioaccumulative in the environment. When this report is specifically referring to lead, the term is spelled out (i.e., the two-letter chemical symbol for lead is not used in this document).

compounds or compound classes initially identified for potential screening assessment (from EPA's Air Toxics Risk Assessment (ATRA) Library) included the following: cadmium compounds, chlordane, chlorinated dibenzodioxins and furans (dioxins), 1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene (DDE), heptachlor, hexachlorobenzene, hexachlorocyclohexane, lead compounds, mercury compounds, methoxychlor, polychlorinated biphenyls (PCB), polycyclic organic matter (POM), toxaphene, and trifluralin. Of these, EPA identified cadmium compounds, dioxins, mercury compounds, lead, POM, as well as arsenic, as PB-HAP of primary concern, based on assessment of national emission totals, toxicity considerations, and bioaccumulation potential. We assess these six PB-HAP for human health risks due to non-inhalation exposure.

We use a tiered approach to evaluate emissions of these PB-HAP for potential non-inhalation risks. This approach is designed to eliminate from further consideration those facilities for which we have confidence that human health risks will not occur due to non-inhalation exposure to their PB-HAP emissions. The approach was developed for use with EPA's peer-reviewed Total Risk Integrated Methodology: Fate, Transport, and Ecological Exposure (TRIM.FaTE) model.

For each carcinogenic PB-HAP, we have derived a screening threshold emission rate at which the maximum excess lifetime cancer risk would be 1-in-1 million. For each PB-HAP that causes noncancer health effects, we have derived a screening threshold emission rate for which the maximum HQ would be 1. The ratio of facility emissions to the screening threshold emission rate is termed a "screening value;" facility emissions that exceed the screening threshold emission rate have a screening value greater than 1. A screening value greater than 1 in any of the tiered screening methods represents a high-end estimate of what the risk or hazard may be; it cannot be equated with a risk value or a HQ (or HI). For example, for a carcinogen, a screening value of 30 (i.e., facility emissions are 30 times above the screening threshold emission rate) means that we are confident that the cancer risk is lower than 30-in-1 million. Similarly, for a non-carcinogen, a screening value of 2 (i.e., facility emissions are 2 times above the screening threshold emission rate) can be interpreted to mean that we are confident that the noncancer HQ would be lower than 2.

For Tier 1, 2, and 3 assessments, we use hypothetical exposure scenarios to assess whether non-inhalation exposures pose a potential human health risk. Exposure scenarios were developed to simulate generic gardening and subsistence farming and subsistence fishing lifestyles. Each screening exposure scenario is designed to represent the upper end of the range of possible exposure levels, such that it is a conservative but not impossible scenario. The exposure scenarios were developed for use in conjunction with the TRIM.FaTE model. These hypothetical exposure scenarios and associated ingestion exposure pathways are shown in Table 2.5-1.

Table 2.5-1. Multipathway Scenarios and Ingestion Pathways

Hypothetical Exposure Scenario	**Fish**	**Breast Milk** [a]	**Beef/Pork /Chicken**	**Dairy Milk**	**Eggs**	**Soil**	**Fruits and Vegetables** [b]
Combined Fisher and Farmer (Tier 1)	x	x	x	x	x	x	x
Fisher (Tier 2)	x	x					
Gardener (urban or rural) (Tier 2)		x			x	x	x
Farmer [c] (Tier 2)		x	x	x	x	x	x
Pollutants of Concern [d]	Hg, Cd, As, dioxin, POM	dioxin	As, dioxin, POM	As, dioxin, POM	As, dioxin, POM	As, dioxin, POM	As, dioxin, POM

[a] Health risks from the breast milk pathway are only associated with exposure to dioxins.
[b] Both protected and unprotected fruits and vegetables are included.
[c] This scenario may be included in a Tier 2 assessment in cases where we have site-specific data indicating that farming operations are present.
[d] The health endpoint for exposure to Hg (as methylmercury) and Cd is noncancer and the health endpoint for exposure to As (as inorganic arsenic), dioxin, and POM is cancer.

For the Tier 1 screening assessment, we determine whether the facility-specific emission rates for each emitted PB–HAP are high enough to create the potential for significant non-inhalation human health risks under reasonable worst-case conditions. We do this by comparing the facility-specific emission rates to the screening threshold emission rates for each PB-HAP for a hypothetical upper-end screening exposure scenario – the combined fisher and farmer scenario. The subsistence fisher scenario assumes a high-end fish consumption rate of 373 g/day for adults, a 99th percentile ingestion rate (Burger, 2002); fish consumption rates for other age groups are presented in Appendix 6. The farmer scenario involves an individual that lives for a 70-year lifetime on a farm near the source and consumes produce grown, and meat and animal products raised, on the farm. The ingestion rates used for these food groups, and for incidental soil ingestion, are set at the 90th percentile of EPA's Exposure Factors Handbook: 2011 Edition (USEPA, 2011) and are considered upper-bound levels. The fisher and farmer exposure scenarios are combined for the Tier 1 TRIM.FaTE model application. See Appendix 6 (*Technical Support Document for TRIM-Based Multipathway Tiered Screening Methodology for RTR*) for a complete discussion of the development and testing of the screening scenario and the screening threshold emission rates.

For those facilities with PB-HAP emissions that exceed the Tier 1 screening threshold emission rate, we conduct a Tier 2 multipathway screening assessment. For the Tier 2 screening assessment, we refine the assessment by using the facility locations and considering two separate exposure scenarios – the fisher scenario and the home gardener scenario (rural or urban, as appropriate). In some cases, if supported by site-specific information, the subsistence farmer scenario is also considered. For each facility, we use the Tier 1 PB-HAP screening threshold emission rate, but with adjustments based on the ingested media and based on an understanding of how exposure concentrations estimated for the screening scenario change with use of the local meteorology and environmental assumptions. The gardener and fisher scenarios replace the Tier 1 combined fisher and farmer scenario as more likely exposure scenarios. The gardener scenario is only evaluated for carcinogenic PB-HAP (i.e., arsenic, dioxin, and POM) because the evaluated non-carcinogens (i.e., mercury and cadmium) accumulate in soil and the farm food chain in much smaller amounts than in fish tissue. For the gardener scenario, the Tier 1 PB-HAP screening threshold emission rates are adjusted to reflect exposure only through soil and farm foods, based on the rural/urban classification of the facility site (with urban gardeners growing and ingesting less home-grown produce than rural gardeners). The gardener scenarios (rural and urban) involve an individual that maintains a garden and consumes produce from this garden for 70 years at his/her residence. The evaluated locations of the gardener correspond to the maximum impacted residential receptor according to the RTR inhalation cancer assessment for each of the 8 wind octants (N, NE, E, SE, …) for all carcinogenic HAPs combined. The screening threshold emission rate can be different at each of these gardener locations, based on distance from the facility and based on local meteorology conditions. The ingestion rates used for the food groups are set at the 90th percentile and mean values for rural and urban, respectively, based on data from EPA's Exposure Factors Handbook: 2011 Edition (USEPA, 2011); both gardeners have incidental soil ingestion rates equal to those of the farmer. The largest of the gardener screening values is identified for each PB-HAP. The fisher scenario is conducted for all of the currently evaluated PB-HAP, whose Tier 1 PB-HAP screening threshold emission rates are adjusted to reflect exposure only through fish ingestion. For the Tier 2 assessment, to fulfill the adult ingestion rate for the fisher scenario, if needed, more than one lake may be included in the modeling in order to reach a cumulative total of 373 acres and achieve the 373-g/day fish ingestion rate. A complete discussion of the bioassay studies used to support the assumption that the biological productivity limitation of each lake is 1 gram of fish caught and consumed per acre of water per day is provided in Appendix 6 of this document. The screening threshold emission rate can be different at each lake location, based on distance from the facility and based on local meteorology conditions.

If we need to include more than one lake in the Tier 2 screening assessment to achieve the 373 g/day ingestion rate, we begin with the lake with the highest modeled chemical concentration of a given PB-HAP group and "fish" up to the lake's biological productivity. We then systematically proceed to other lakes based on concentration, until the 373 g/day target is met. A maximum travel radius of 50 km relative to the facility is used to maintain a realistic scenario for the fisher. The final Tier 2 screening result for the fisher can be expressed as the sum of the screening result from each lake that is fished (which is based on the amount of fish ingested from each lake multiplied by the chemical concentration in fish). If the highest-concentration lake is at least 373 acres in size, the adult fisher catches and consumes 373 g/day of fish from that lake. If the cumulative size of multiple visited lakes exceeds 373 acres, the model includes from the final lake only the amount of fish necessary to satisfy the ingestion rate (i.e., to reach 373 g/day). If the total acreage of lakes within 50 km is less than 373 acres, the screening result reflects a reduced ingestion rate based on the smaller lake acreage. The order of fished lakes for a facility follows the order of PB-HAP concentration in fish from highest to lowest based on the facility's emissions. However, the resulting screening value calculations described above also potentially consider chemical inputs from emissions from multiple facilities. If a fished lake for one facility ("Facility A") is also within 50 km of another facility ("Facility B") in the source category, then the lake receives chemical input from emissions from two facilities. The order of fished lakes for Facility A considers only Facility A's chemical inputs to the lake, but the final fisher screening values for Facility A include the summed chemical inputs of Facility A and Facility B. If that lake was also fished for the Facility B scenario, then the same process would be applied to Facility B.

The Tier 2 assessment yields a facility-specific screening value for each PB-HAP for the fisher scenario and for the gardener scenario. If information is available to identify subsistence farming operations, the Tier 2 assessment will also include a screening value for the farmer scenario. Tier 2 screening values are evaluated for the source category to determine whether further refined screening is necessary for those facilities that may pose a significant risk. A finding that a facility's emissions exceed the Tier 2 screening threshold emission rate does not necessarily mean that multipathway impacts are significant, only that we cannot rule out that possibility based on the results of the screening assessment. See Appendix 6 of this document for a complete discussion of the Tier 2 screening assessment.

For facilities for which the Tier 2 screening value(s) indicate a potential health risk to the public, we can conduct a Tier 3 multipathway screening assessment. The Tier 3 screening assessment has three individual stages; we progress through these stages until the facility's screening values indicate that the emissions are unlikely to pose health risks to the public, or until all three stages are complete.

The first stage of a Tier 3 screening assessment, the lake-assessment stage, is a refinement of the fisher scenario. We examine the fished lakes from Tier 2 and evaluate the existence, the potential purpose, the accessibility and fishability, and the suitability of the lakes for the models and methods used in the screening assessments. We do not reasonably expect a subsistence fisher to catch and consume fish from lakes or ponds that are for industrial or wastewater disposal; are covered in thick plant growth (e.g., swamps or marshes); are clearly closed to public use; or no longer exist (i.e., filled or drained). TRIM.FaTE is not configured to model chemical processes and environmental fate and transport mechanisms in saltwater or brackish waters, nor is it configured to model the very large watersheds and water dynamics of rivers, bays or very large lakes (e.g., larger than 100,000 acres)[7]. We use aerial imagery and web inquires to evaluate whether any Tier 2 fished lakes meet these disqualifying criteria

[7] Very large lakes and bays (i.e., those larger than 100,000 acres) are not included because their watersheds are too large and their lake dynamics are too complex to realistically model in the TRIM.FaTE system. Lakes and bays larger than 100,000 acres include the Great Lakes, the Great Salt Lake, Lake Okeechobee, Lake Pontchartrain, Lake Champlain, Green Bay, and Galveston Bay.

and, if so, remove those lakes from all future screening assessments. If we remove a lake from a facility's assessment, and the total acres of fished lakes drops below the target of 373 acres, we evaluate the previously unfished lake with the highest chemical concentration, and so on, until the sizes of the qualifying lakes collectively comprise at least 373 acres or all lakes have been evaluated. We then rerun the fisher screening scenario with the revised lake data set. If the PB-HAP emissions for a facility exceed the fisher screening threshold emission rate based on the revised lake data set, we can conduct the next stage of the Tier 3 screening assessment (i.e., the plume-rise screen); otherwise, the emissions are considered unlikely to pose significant health risks in the fisher scenario.

The second stage of a Tier 3 screening assessment, the plume-rise stage, is a refinement of the previously assessed scenarios (i.e., Tier 2 farmer, Tier 2 gardener, Tier 3 lake-assessment fisher) where emissions exceeded screening threshold emission rates. We use site-specific hourly meteorology and facility-specific emission-point characteristics to estimate the fraction of annual emissions that stay within TRIM.FaTE's mixing layer where exposure occurs (i.e., that do not exit the mixing layer). In Tiers 1 and 2, all chemicals are emitted inside the mixing layer and are available for ground-level exposure. In reality, meteorological conditions and emission-point characteristics can cause emissions occasionally to reach higher than the mixing layer. In TRIM.FaTE, any emissions exiting the mixing layer do not reenter the mixing layer, resulting in no ground-level exposure for those emissions. In this Tier 3 stage, we use thermodynamic equations with local hourly meteorology and facility stack parameters to calculate hourly plume-rise heights. The fraction of annual hours during which the plume-rise height is less than the mixing-layer height equals the fraction of annual emissions available for human exposure in the screening assessment. We calculate these fractions for the location of each fished lake and for each relevant garden because lakes and gardens can be in different directions from the facility; thus, these calculations are conditional on wind direction. The results of this stage of Tier 3 are revised fisher and/or gardener screening values for each relevant PB-HAP and facility, accounting for emissions deposited above the mixing layer. If the revised screening value still indicates potential health risks to the public, we can proceed to the final stage of the Tier 3 screening assessment (i.e., the time-series screen); otherwise, the PB-HAP emissions are considered unlikely to pose significant risks.

In the third and final stage of a Tier 3 screening assessment, the time-series assessment, we can conduct new runs of TRIM.FaTE for each relevant lake and/or garden location for a facility for every PB-HAP that represents a risk concern based upon the Tier 3 plume-rise assessment. For these model runs, we start with the screening configuration corresponding to the lake and/or garden location, and we use site-specific hourly meteorology and the hourly plume-rise values calculated in the Tier 3 plume-rise assessment. Allowing TRIM.FaTE- to model chemical fate and transport with hour-by-hour changes in meteorology and plume rise produces a more accurate estimate of chemical concentrations in media of interest, as compared to the static values used in Tier 2 and the post-processing adjustments made in the Tier 3 plume-rise assessment. If a facility's model-estimated PB-HAP screening-level cancer risk is below 1-in-1 million (or screening-level HQ is below 1 for non-carcinogens), the emissions are considered unlikely to pose significant risks.

If a facility's PB-HAP Tier 3 screening results still indicate a potential health risk to the public and data are available, we may elect to conduct a more refined multipathway assessment. A refined assessment replaces some of the assumptions made in the screening with site-specific data. The refined assessment also uses the TRIM.FaTE model and facility-specific emission rates for each PB-HAP. Many variables are available to consider in a refined multipathway assessment, and we have developed a protocol to maintain consistency across source categories. This protocol can be found in Appendix 7 of this document (*Protocol for Site-Specific Multipathway Risk Assessment*) and details of the site-specific multipathway assessment can be found in Appendix 11 of this document (*Site-Specific Human Health Multipathway Residual Risk Assessment Report*).

Lead

We take a different approach for assessing lead compounds. In evaluating the potential multipathway risks from emissions of lead compounds, rather than developing a screening emission rate for them, we compare maximum estimated chronic atmospheric concentrations with the current national ambient air quality standard (NAAQS) for lead. Values below the NAAQS are considered to have a low potential for multipathway risks.

The NAAQS value, a public health policy judgment, incorporates the Agency's most recent health evaluation of air effects of lead exposure for the purposes of setting a national ambient air quality standard. In setting this value, the Administrator promulgated a standard that was requisite to protect public health with an adequate margin of safety. We consider values below the level of the primary NAAQS to protect against multipathway risks because, as mentioned above, the primary NAAQS is set to protect public health with an adequate margin of safety. However, ambient air lead concentrations above the NAAQS are considered to pose the potential for increased risk to public health. We consider this NAAQS assessment to be a refined analysis given: 1) the numerous health studies, detailed risk and exposure analyses, and level of external peer and public review that went into the development of the primary NAAQS for lead, combined with 2) the site-specific dispersion modeling used in this assessment to estimated ambient lead concentrations due to the source category emissions. It should be noted, however, that this comparison does not account for possible population exposures to lead from sources other than the one being modeled; for example, via consumption of water from untreated local sources or ingestion of locally grown food. Nevertheless, the Administrator judged that such a standard would protect, with an adequate margin of safety, the health of children and other at-risk populations against an array of adverse health effects, most notably including neurological effects, particularly neurobehavioral and neurocognitive effects, in children (73 FR 67007). The Administrator, in setting the standard, also recognized that no evidence or risk-based bright line indicated a single appropriate level. Instead, a collection of scientific evidence and other information was used to select the standard from a range of reasonable values (73 FR 67006).

We further note that comparing ambient lead concentrations to the NAAQS for lead, considering the level, averaging time, form and indicator, also informs whether there is the potential for adverse environmental effects. This is because the secondary lead NAAQS, set to protect against adverse welfare effects (including adverse environmental effects), has the same averaging time, form, and level as the primary standard. Thus, ambient lead concentrations above the NAAQS for lead also indicate the potential for adverse environmental effects.

2.6 Environmental risk assessment

The EPA has developed a screening approach to examine the potential for adverse environmental effects, as required under section 112(f)(2)(A) of the CAA. The environmental screening assessment focuses on the following eight environmental HAP:

- Six persistent bioaccumulative HAP (PB-HAP) – cadmium, dioxins, POM, mercury (both inorganic mercury and methylmercury), arsenic, and lead;
- Two acid gases – hydrochloric acid (HCl) and hydrofluoric acid (HF).

HAP that persist and bioaccumulate are of particular environmental concern because they accumulate in the soil, sediment, and water. The acid gases – HCl and HF – were included due to their well-documented potential to cause direct damage to terrestrial plants. See Appendix 9 of this document (*Environmental Risk Screening Assessment*) for a more detailed discussion of the environmental risk screening assessment.

For the environmental risk screening assessment, EPA first determines whether any facilities in the source category emit any of the eight environmental HAP. If one or more of the environmental HAP are emitted by at least one facility in the source category, we proceed to the second step of the environmental risk screening assessment.

For cadmium, mercury, POM, arsenic, and dioxins, the environmental screening assessment consists of the same three tiers used in the multipathway human health risk assessment (see Section 2.5). In the first tier, the same TRIM.FaTE modeling used in human health risk assessment is conducted, using reasonable worst-case environmental conditions to identify screening threshold emission rates corresponding to ecological benchmarks for soil, fish, surface water, and sediment. For each facility and PB-HAP, facility emissions are compared to these screening threshold emission rates to determine the potential for significant impacts on off-site ecological receptors. The ratio of facility emissions to the screening threshold emission rate is termed a "screening value." Facility emissions that exceed the screening threshold emission rate have a screening value greater than 1, and risks above levels of concern for ecological receptors are possible. Screening values below 1 indicate that risks to ecological receptors are likely below levels of concern.

For those facilities with PB-HAP emissions that exceed a Tier 1 screening threshold emission rate, we conduct a Tier 2 screening assessment. In Tier 2, the Tier 1 screening threshold emission rates are adjusted to account for local meteorology and environmental assumptions. For lake-related ecological receptors, actual locations of lakes within 50 km of the facility are identified, and the screening threshold emission rate can be different at each lake location based on distance from the facility and based on local meteorology conditions. After the screening value (i.e., ratio of facility emissions to screening threshold emission rate) is calculated at each lake, the largest screening value is identified. Screening threshold emission rates for soil receptors are evaluated at many locations surrounding the facility and are also impacted by distance from facility and local meteorology. For soil receptors in Tier 2, we are interested in the overall average screening value across all soil receptors (for a given facility and PB-HAP), and we are also interested in the total area in the vicinity of the facility where screening values are above 1 (for a given facility and PB-HAP). If a lake-related screening value is above 1, or the soil screening value is above 1 at any location, or the overall average soil screening value is above 1, it does not necessarily mean that the ecological effects are significant, but only that we cannot rule out that possibility. For facilities with Tier 2 screening values above 1, we can evaluate their emissions further in Tier 3.

Like in the multipathway human health risk assessment, in Tier 3 of the environmental screening assessment, we examine the suitability of the lakes around the facilities to support life and remove those that are not (e.g., lakes that have been filled in or are industrial ponds), adjust emissions for plume-rise, and conduct hour-by-hour time-series assessments. For the lake assessment, we remove from the screening any lakes that appear to be industrial, for wastewater disposal, or no longer exist. TRIM.FaTE is not configured to model chemical processes and environmental fate and transport mechanisms in saltwater or brackish waters, nor is it configured to model the very large watersheds and water dynamics of rivers or very large lakes (e.g., larger than 100,000 acres); these types of water bodies are also removed from the screening assessment. Unlike the multipathway human health risk assessment, we assume that if lakes that are swampy or are not publicly accessible, they still can support ecological life and some animals will still eat from them. After lakes are removed that meet these disqualifying criteria, lake-related receptors are rescreened. For the plume-rise assessment, as in the human health assessment, we adjust the facility's previously calculated screening value based on the fraction of facility emissions that remain in the mixing layer where exposure occurs, after accounting for plume rise (which is based on site-specific meteorology and facility-specific emission-point characteristics). If these Tier 3 adjustments still indicate that ecological risks could be above levels of concern (i.e., screening values are above 1), as in the human health assessment, we can conduct new TRIM.FaTE modeling using the screening configuration corresponding to the relevant lake and/or soil locations, site-specific hourly meteorology, and hourly plume-rise values. If such modeling results in screening-level media concentrations or doses above benchmark levels, we may elect to conduct a more refined assessment using more site-specific information. If, after additional refinement, the media concentrations or doses are above benchmark levels, the facility may have the potential to cause adverse environmental effects.

For acid gases, the environmental screening assessment evaluates the potential phytotoxicity and reduced productivity of plants due to chronic exposure to acid gases. The environmental risk screening methodology for acid gases is a single-tier screening assessment that compares the average off-site ambient air concentration over the modeling domain to ecological benchmarks for each of the acid gases. For purposes of an ecological risk screening assessment, EPA identifies a potential for adverse environmental effects to plant communities from exposure to acid gases when the average off-site ambient air concentration over the modeling domain for a facility exceeds the ecological benchmark for that acid gas. In such cases, we further investigate factors such as the magnitude of the exceedance and the characteristics of the area of exceedance (e.g., land use of exceedance area, size of exceedance area) to determine whether the facility's emissions have the potential to cause adverse environmental effects.

Lead

For lead compounds, we currently do not have the ability to calculate media concentrations using the TRIM.FaTE model. However, air concentrations of lead are already calculated as part of the human health exposure and risk assessment using HEM-3. To evaluate the potential for adverse environmental effects from lead, we compare the average modeled air concentrations of lead around each facility in the source category to the level of the secondary NAAQS for lead. The secondary lead NAAQS is a reasonable means of evaluating environmental risk because it is set to provide substantial protection against adverse welfare effects which can include "effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being." [8] We investigate any modeled exceedances of the lead NAAQS in a manner similar to that noted above for acid gases.

2.7 Dose-response assessment

2.7.1 Sources of chronic dose-response information

Dose-response assessments (carcinogenic and non-carcinogenic) for chronic exposure (either by inhalation or ingestion) for the HAP reported in the emissions inventory for this source category are based on the EPA Office of Air Quality Planning and Standards' (OAQPS) existing recommendations for HAP (USEPA, 2014a). This information has been obtained from various sources and prioritized according to (1) conceptual consistency with EPA risk assessment guidelines and (2) level of peer review received. The prioritization process was aimed at incorporating into our assessments the best available science with respect to dose-response information. The recommendations are based on the following sources, in order of priority:

1) **U.S. Environmental Protection Agency (EPA).** EPA has developed dose-response assessments for chronic exposure for many HAP. These assessments typically provide a qualitative statement regarding the strength of scientific data and specify a reference concentration (RfC, for inhalation) or reference dose (RfD, for ingestion) to protect against effects other than cancer and/or a unit risk estimate (URE, for inhalation) or slope factor (SF, for ingestion) to estimate the probability of developing cancer. The RfC is defined as an "estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including

[8] A secondary standard, as defined in Section 109(b)(2), must "specify a level of air quality the attainment and maintenance of which, in the judgment of the Administrator, based on criteria, is requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of [the] pollutant in the ambient air." Welfare effects as defined in section 302(h) (42 U.S.C. 7602(h)) include, but are not limited to, "effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being."

sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime." The RfD is "an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily oral exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime." The URE is defined as "the upper-bound excess cancer risk estimated to result from continuous lifetime exposure to an agent at a concentration of 1 $\mu g/m^3$ in air." The SF is "an upper bound, approximating a 95 percent confidence limit, on the increased cancer risk from a lifetime exposure to an agent. This estimate, [is] usually expressed in units of proportion (of a population) affected per mg/kg-day…"

EPA disseminates dose-response assessment information in several forms, based on the level of review. The Integrated Risk Information System (IRIS) is an EPA database that contains scientific health assessment information, including dose-response information. All IRIS assessments since 1996 have also undergone independent external peer review. The current IRIS process includes review by EPA scientists, interagency reviewers from other federal agencies, and the public, as well as peer review by independent scientists external to EPA. New IRIS values are developed and old IRIS values are updated as new health effects data become available. Refer to the IRIS Agenda for detailed information on status and scheduling of current individual IRIS assessments and updates. EPA's science policy approach, under the current carcinogen guidelines, is to use linear low-dose extrapolation as a default option for carcinogens for which the mode of action (MOA) has not been identified. We expect future EPA dose-response assessments to identify nonlinear MOAs where appropriate, and we will use those analyses (once they are peer reviewed) in our risk assessments. At this time, however, there are no available carcinogen dose-response assessments for inhalation exposure that are based on a nonlinear MOA.

2) **U.S. Agency for Toxic Substances and Disease Registry (ATSDR).** ATSDR, which is part of the US Department of Health and Human Services, develops and publishes Minimal Risk Levels (MRLs) for inhalation and oral exposure to many toxic substances. As stated on the ATSDR web site: "Following discussions with scientists within the Department of Health and Human Services (HHS) and the EPA, ATSDR chose to adopt a practice similar to that of the EPA's Reference Dose (RfD) and Reference Concentration (RfC) for deriving substance specific health guidance levels for non-neoplastic endpoints." The MRL is defined as "an estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects (other than cancer) over a specified duration of exposure." ATSDR describes MRLs as substance-specific estimates to be used by health assessors to select environmental contaminants for further evaluation.

3) **California Environmental Protection Agency (CalEPA).** The CalEPA Office of Environmental Health Hazard Assessment has developed dose-response assessments for many substances, based both on carcinogenicity and health effects other than cancer. The process for developing these assessments is similar to that used by EPA to develop IRIS values and incorporates significant external scientific peer review. As

stated in the CalEPA Technical Support Document for developing their chronic assessments, the guidelines for developing chronic inhalation exposure levels incorporate many recommendations of the U.S. EPA (USEPA, 1994a) and NAS (NAS, 1994). The noncancer information includes available inhalation health risk guidance values expressed as chronic inhalation reference exposure levels (RELs). CalEPA defines the REL as "the concentration level at or below which no health effects are anticipated in the general human population." CalEPA's quantitative dose-response information on carcinogenicity by inhalation exposure is expressed in terms of the URE, defined similarly to EPA's URE.

For certain HAP, the dose-response information, based on this prioritization, is limited. To address data gaps, increase accuracy, and avoid underestimating risk, we made additional changes to some of the chronic inhalation exposure values. These important changes, outlined below and reflected in Appendix 8 (*Dose-Response Values Used in the RTR Risk Assessments*) to this document, are as follows:

1) **Acrolein.** The EPA derived an IRIS RfC for acrolein in 2003 (USEPA, 2003), which was based on a 1978 subchronic rodent study that identified a lowest-observed-adverse-effect level (LOAEL) for nasal lesions (Feron et al., 1978). In 2008, the California EPA derived a chronic reference exposure level for acrolein that was based on a more recent subchronic rodent study, which identified a no-observed-adverse-effect level (NOAEL) for nasal lesions (CalEPA, 2008; Dorman et al., 2008). Because both studies identified nasal lesions as the critical effect and because the Dorman et al. (2008) study identified a NOAEL, we have decided to use the CalEPA REL for acrolein in this RTR risk assessment. The EPA is in the process of updating the IRIS RfC for acrolein. If the RfC is updated prior to signature of the final rule, we will use it in the risk assessment for the final rule.

2) **Manganese**. The EPA considers the ATSDR MRL for manganese (Mn) the most appropriate chronic inhalation reference value to be used in RTR assessments. There is an existing IRIS RfC for Mn (USEPA, 1993a), and ATSDR published an assessment of Mn toxicity which includes a chronic inhalation reference value (i.e., an ATSDR Minimal Risk Level, MRL). (ATSDR, 2012). Both the 1993 IRIS RfC and the 2012 ATSDR MRL were based on the same study (Roels et al., 1992); however, ATSDR used updated dose-response modeling methodology (benchmark dose approach) and considered recent pharmacokinetic findings to support their MRL derivation. Because of the updated methods, EPA has determined that the ATSDR MRL is the appropriate health reference value to use in RTR risk assessments.

3) **Polycyclic Organic Matter.** EPA has identified appropriate UREs for many individual compounds of POM, published in the sources used for RTR risk assessments. When an individual POM compound is reported in the emission inventory for the source category, we use the appropriate URE for that compound. However, if in the emission inventory for the source category a POM compound is reported for which EPA has not identified a URE, or when POM are not speciated into individual compounds, then EPA applies simplifying assumptions so that cancer risk

can be quantitatively evaluated without substantially under- or over-estimating risk (which can occur if all reported POM emissions were assigned the same URE). To accomplish this, EPA places each POM compound into one of eight POM groups, generally defined by toxicity and the estimated emission profile of POM compounds. POM Groups 1 and 2 include unspeciated POM (emissions reported as "polycyclic organic matter") and individual POM compounds with no URE assigned from the sources used in RTR risk assessments. With two exceptions, both Groups 1 and 2 are assigned a URE equal to 5 percent of that for pure benzo[a]pyrene; the two exceptions are benzo[a]fluoranthene and generic "benzofluoranthenes", which received the URE of benzo[b]fluoranthene. POM Groups 3 through 7 comprise POM compounds for which UREs are available from the sources used for RTR risk assessments, except for benzo[b+k]fluoranthene and benzo[g,h,i]fluoranthene which receive the URE of benzo[b]fluoranthene. If reported emissions are for a specific compound in these groups, then EPA evaluates the cancer risk of the compound using its unique URE if one has been derived or its group URE if one has not been specifically derived. If the reported emissions are for a specific POM group rather than a compound within the group, then EPA evaluates the cancer risk of the POM group using a URE value that is close to the average of the UREs of the individual compounds within the group. POM Group 8 is composed of unspeciated polycyclic aromatic hydrocarbons (PAH) reported as 7-PAH and are assigned a URE equal to approximately 18 percent of that for pure benzo[a]pyrene. In addition, we have concluded that three PAHs—anthracene, phenanthrene and pyrene—are not carcinogenic and therefore no URE is assigned. Details of the analysis that led to this conclusion can be found in the document titled Development of a Relative Potency Factor (RPF) Approach for Polycyclic Aromatic Hydrocarbon (PAH) Mixtures: In Support of Summary Information of the Integrated Risk Information System (IRIS).

4) **Glycol Ethers.** Often in an emission inventory, the glycol ethers are reported only as the total mass for the entire group without distinguishing among individual glycol ether compounds. In other cases, emissions of individual glycol ether compounds that had not been assigned dose-response values were reported. To avoid underestimating the health hazard associated with glycol ethers, we protectively apply the RfC for ethylene glycol methyl ether (the most toxic glycol ether for which an assessment exists) to glycol ether emissions of unspecified composition.

5) **Lead.** We consider the primary NAAQS for lead, which incorporates an adequate margin of safety, to be protective of all potential health effects for the most susceptible populations. The NAAQS, developed using the EPA Integrated Exposure, Uptake, Biokinetic Model, was preferred over the RfC for noncancer adverse effects because the NAAQS for lead was developed using more recent toxicity and dose-response information on the noncancer adverse impacts of lead. The NAAQS for lead was set to protect the health of the most susceptible children and other potentially at-risk populations against an array of adverse health effects, most notably including neurological effects, particularly neurobehavioral and neurocognitive effects (which are the effects to which children are most sensitive). The lead NAAQS, a rolling 3-

month average level of lead in total suspended particles, is used as a long-term value in the RTR risk assessment.

6) **Nickel compounds.** To provide a conservative estimate of the potential cancer risks, the EPA considers the IRIS URE value for nickel subsulfide (which is considered the most potent carcinogen among all nickel compounds) to be the most appropriate value to be used in RTR assessments. Based on consistent views of major scientific bodies, such as the National Toxicology Program (NTP) in their 14th Report of the Carcinogens (RoC) (NTP, 2016), the International Agency for Research on Cancer (IARC, 1990), and other international agencies (WHO, 1991) that consider all nickel compounds to be carcinogenic, we currently consider all nickel compounds to have the potential of being carcinogenic to humans. The 14th RoC states that "the combined results of epidemiological studies, mechanistic studies, and carcinogenic studies in rodents support the concept that nickel compounds generate nickel ions in target cells at sites critical for carcinogenesis, thus allowing consideration and evaluation of these compounds as a single group." Although the precise nickel compound (or compounds) responsible for carcinogenic effects in humans is not always clear, studies indicate that nickel sulfate and the combinations of nickel sulfides and oxides encountered in industrial emissions of nickel mixtures cause cancer in humans (these studies are summarized in a review by Grimsrud et al., 2010). The major scientific bodies mentioned above have also recognized that there may be differences in the toxicity and/or carcinogenic potential across the different nickel compounds. For this reason, and given that there are two additional URE values[9] derived for exposure to mixtures of nickel compounds (as a group) that are 2-3 fold lower than the IRIS URE for nickel subsulfide, the EPA considers it reasonable, in some instances (e.g., when high quality data are available on the composition of nickel emissions from a specific source category), to use a value that is 50 percent of the IRIS URE for nickel subsulfide for providing an estimate of the lower end of the plausible range of cancer potency values for different mixtures of nickel compounds.

7) **Carbonyl Sulfide.** Although the health effects data for carbonyl sulfide (COS) are very limited, a series of studies (Morgan et. al., 2004; Herr et. al., 2007; Sills et. al., 2004) conducted by the National Toxicology Program have shown that the major concern regarding exposure to COS is its potential for neurotoxicity. These studies have shown consistently and at the same range of COS concentrations that the brain is a target organ for COS toxicity. Since appropriate health effects benchmarks have not been derived by our preferred sources of dose-response data including IRIS, ATSDR, and Cal EPA, the EPA has used the data from the above referenced studies to derive a chronic screening benchmark level for COS. A chronic screening level of 163 $\mu g/m^3$ was developed for COS from a No Observed Adverse Effects Level (NOAEL) of 200 ppm based on brain lesions and neurophysiological alterations in rodents. Additional

[9] Two UREs (other than the current IRIS values) have been derived for nickel compounds as a group: one developed by the California Department of Health Services (http://www.arb.ca.gov/toxics/id/summary/nickel_tech_b.pdf) and the other by the Texas Commission on Environmental Quality (http://www.tceq.texas.gov/assets/public/implementation/tox/dsd/facts/nickel_&_compounds.pdf).

details on the derivation of the chronic screening level for COS can be found in Appendix 8.

8) **Pollutant Groups.** In the case of HAP groups such as cyanide compounds, mercury compounds, antimony compounds and others, the most conservative dose-response value in the chemical group is used as a surrogate for other compounds in the group for which dose-response values are not available. This is done to examine, under conservative assumptions, whether those HAP that lack dose-response values may pose an unacceptable risk and require further examination.

9) **Mutagenic Mode of Action.** For carcinogenic chemicals acting via a mutagenic mode of action (i.e., chemicals that cause cancer by damaging genes), we estimate risks to reflect the increased carcinogenicity of such chemicals during childhood. This approach is explained in detail in the Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens. Where available data do not support a chemical-specific evaluation of differences between adults and children, the Supplemental Guidance recommends using the following default adjustment factors for early-life exposures: increase the carcinogenic potency by 10-fold for children up to 2 years old and by 3-fold for children 2 to 15 years old. These adjustments have the aggregate effects of increasing by about 60 percent the estimated risk (a 1.6-fold increase) for a lifetime of constant inhalation exposure. EPA uses these default adjustments only for carcinogens known to be mutagenic for which data to evaluate adult and juvenile differences in toxicity are not available. The UREs for several HAP (see Appendix 8) were adjusted upward, by multiplying by a factor of 1.6, to account for the increased risk during childhood exposures. Although trichloroethylene is carcinogenic by a mutagenic mode of action, the age-dependent adjustment factor for the URE only applies to the portion of the slope factor reflecting risk of kidney cancer. For full lifetime exposure to a constant level of trichloroethylene exposure, the URE is adjusted upward by a factor of 1.12 (rather than 1.6 as discussed above). For more information on applying age-dependent adjustment factors in cases where exposure varies over the lifetime, see Toxicological Review of Trichloroethylene. The URE for vinyl chloride includes exposure from birth, although the IRIS assessment contains UREs for both exposure from birth and exposure during adulthood. This value already accounts for childhood exposure; thus, no additional factor is applied.

2.7.2 Sources of acute dose-response information

Hazard identification and dose-response assessment information for preliminary acute inhalation exposure assessments is based on the existing recommendations of OAQPS for HAP (USEPA, 2014b). When the benchmarks are available, the results from acute screening assessments are compared to both "no effects" reference levels for the general public, such as the California Reference Exposure Levels (RELs), and to emergency response levels, such as Acute Exposure Guideline Levels (AEGLs) and Emergency Response Planning Guidelines (ERPGs), with the recognition that the ultimate interpretation of any potential risks associated with an estimated exceedance of a particular reference level depends on the definition of that level and any limitations expressed therein. Comparisons among different available inhalation health effect reference values (both acute and chronic) for selected HAP can be found in an EPA document of graphical arrays (USEPA, 2009b).

California Acute Reference Exposure Levels (RELs). The California Environmental Protection Agency (CalEPA) has developed acute dose-response reference values for many substances, expressing the results as acute inhalation RELs.

> The acute REL is defined by CalEPA as "the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration (OEHHA, 2015). RELs are based on the most sensitive, relevant, adverse health effect reported in the medical and toxicological literature. RELs are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety. Since margins of safety are incorporated to address data gaps and uncertainties, exceeding the REL does not automatically indicate an adverse health impact." Acute RELs are developed for 1-hour (and 8-hour) exposures. The values incorporate uncertainty factors similar to those used in deriving EPA's inhalation RfCs for chronic exposures.

Acute Exposure Guideline Levels (AEGLs). AEGLs are developed by the National Advisory Committee (NAC) on Acute Exposure Guideline Levels (NAC/AEGL) for Hazardous Substances and then reviewed and published by the National Research Council. As described in the Committee's Standing Operating Procedures, AEGLs "represent threshold exposure limits for the general public and are applicable to emergency exposures ranging from 10 min to 8 h." Their intended application is "for conducting risk assessments to aid in the development of emergency preparedness and prevention plans, as well as real time emergency response actions, for accidental chemical releases at fixed facilities and from transport carriers." The document states that "the primary purpose of the AEGL program and the NAC/AEGL Committee is to develop guideline levels for once-in-a-lifetime, short-term exposures to airborne concentrations of acutely toxic, high-priority chemicals." In detailing the intended application of AEGL values, the document states, "It is anticipated that the AEGL values will be used for regulatory and nonregulatory purposes by U.S. Federal and State agencies, and possibly the international community in conjunction with chemical emergency response, planning, and prevention programs. More specifically, the AEGL values will be used for conducting various risk assessments to aid in the development of emergency preparedness and prevention plans, as well as real-time emergency response actions, for accidental chemical releases at fixed facilities and from transport carriers."

The NAC/AEGL defines AEGL-1 and AEGL-2 as:

> "AEGL-1 is the airborne concentration (expressed as ppm or mg/m^3) of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic nonsensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure."

> "AEGL-2 is the airborne concentration (expressed as ppm or mg/m^3) of a substance above which it is predicted that the general population, including susceptible individuals, could

experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape."

"Airborne concentrations above AEGL-1 represent exposure levels that can produce mild and progressively increasing but transient and nondisabling odor, taste, and sensory irritation or certain asymptomatic, nonsensory effects. With increasing airborne concentrations above each AEGL, there is a progressive increase in the likelihood of occurrence and the severity of effects described for each corresponding AEGL. Although the AEGL values represent threshold levels for the general public, including susceptible subpopulations, such as infants, children, the elderly, persons with asthma, and those with other illnesses, it is recognized that individuals, subject to unique or idiosyncratic responses, could experience the effects described at concentrations below the corresponding AEGL."

Emergency Response Planning Guidelines (ERPGs). The American Industrial Hygiene Association (AIHA) has developed ERPGs for acute exposures at three different levels of severity. These guidelines represent concentrations for exposure of the general population (but not particularly sensitive persons) for up to 1 hour associated with effects expected to be mild or transient (ERPG-1), irreversible or serious (ERPG-2), and potentially life-threatening (ERPG-3).

ERPG values are described in their supporting documentation as follows: "ERPGs are air concentration guidelines for single exposures to agents and are intended for use as tools to assess the adequacy of accident prevention and emergency response plans, including transportation emergency planning, community emergency response plans, and incident prevention and mitigation."

ERPG-1 and ERPG-2 values are defined by AIHA's Standard Operating Procedures as follows:

"ERPG-1 is the maximum airborne concentration below which nearly all individuals could be exposed for up to 1 hour without experiencing more than mild, transient health effects or without perceiving a clearly defined objectionable odor."

"ERPG-2 is the maximum airborne concentration below which nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious adverse health effects or symptoms that could impair an individual's ability to take protective action."

In the RTR program, EPA assesses acute risk using toxicity values derived from one hour exposures. Based on an in-depth examination of the available acute value for nickel [California EPA's acute (1-hour) REL], we have concluded that this value is not appropriate to use to support EPA's risk and technology review rules. This conclusion considers the effect on which the acute REL is based; aspects of the methodology used in its derivation; and how this assessment stands in comparison to the ATSDR toxicological assessment, which considered the broader nickel health effects database.

The broad nickel noncancer health effects database strongly suggests that the respiratory tract is the primary target of nickel toxicity following inhalation exposure. The available database on acute noncancer respiratory effects is limited and was considered unsuitable for quantitative analysis of nickel toxicity by both California EPA (OEHHA, 2015) and ATSDR (ATSDR, 2018a). The California EPA's acute (1-hour) REL is based on an alternative endpoint, immunotoxicity in mice, specifically depressed antibody response measured in an antibody plaque assay.

In addition, the current California acute (1-hour) REL for Ni includes the application of methods that depart from those described in EPA guidelines. Specifically, the (1-hour) REL applies uncertainty factors that depart from the defaults in EPA guidelines and does not apply an inhalation dosimetric adjustment factor.

Further, the ATSDR's intermediate MRL (relevant to Ni exposures for a time frame between 14 and 364 days), was established at the same concentration as the California EPA (1- hour) REL, indicating that exposure to this concentration "is likely to be without appreciable risk of adverse noncancer effects" (MRL definition)(ATSDR, 2018b) for up to 364 days.

We have high confidence in the nickel ATSDR intermediate MRL. Our analysis of the broad toxicity database for nickel indicates that this value is based on the most biologically relevant endpoint. That is, the intermediate MRL is based on a scientifically sound study of acute respiratory toxicity. Furthermore, this value is supported by a robust subchronic nickel toxicity database and was derived following guidelines that are consistent with EPA guidelines (USEPA, 2002b).

Finally, there are no AEGL-1/ERPG-1 or AEGL-2/ERPG-2 values available for nickel. Thus, for all the above reasons, we will not include Ni in our acute analysis for this source category or in future assessments unless and until an appropriate 1-hour value becomes available.

2.8 Risk characterization

2.8.1 General

The final product of the risk assessment is the risk characterization, in which the information from the previous steps is integrated and an overall conclusion about risk is synthesized that is complete, informative, and useful for decision makers. In general, the nature of this risk characterization depends on the information available, the application of the risk information and the resources available. In all cases, major issues associated with determining the nature and extent of the risk are identified and discussed. Further, it is EPA's policy that a risk characterization be prepared in a manner that is clear, transparent, reasonable, and consistent with other risk characterizations of similar scope prepared across programs in the Agency. These principles of transparency and consistency have been reinforced by the Agency's *Risk Characterization Handbook* (USEPA, 2000a), in the Agency's information quality guidelines (USEPA, 2002a), and in the Office of Management and Budget (OMB) Memorandum on Updated Principles for Risk Analysis (OMB, 2007), and they are incorporated in these assessments.

Estimates of health risk are presented in the context of uncertainties and limitations in the data and methodology. Through our tiered, iterative analytical approach, we have attempted to reduce both uncertainty and bias to the greatest degree possible in these assessments, within the limitations of available time and resources. We provide summaries of risk metrics (including maximum individual cancer risks and noncancer hazards, as well as cancer incidence estimates) along with a discussion of the major uncertainties associated with their derivation to provide decision makers with the fullest picture of the assessment and its limitations.

For each carcinogenic HAP included in an assessment for which a potency estimate is available, individual and population cancer risks are calculated by multiplying the corresponding lifetime average exposure estimate by the appropriate URE. This calculated cancer risk is defined as the upper-bound probability of developing cancer over a 70-year period (i.e., the assumed human lifespan) at that exposure. Because UREs for most HAP are upper-bound estimates, actual risks at a given exposure level may be lower than predicted.

Increased cancer incidence for the entire population within the area of analysis is estimated by multiplying the estimated lifetime cancer risk for each census block by the number of people residing in that block, then summing the results for the entire modeled domain. This lifetime population incidence estimate is divided by 70 years to obtain an estimate of the number of cancer cases per year.

Unlike linear dose-response assessments for cancer, noncancer health hazards generally are not expressed as a probability of an adverse occurrence. Instead, the estimated human health risk for noncancer effects is expressed by comparing an exposure to a reference level as a ratio. The hazard quotient (HQ) is the estimated exposure divided by a reference level (e.g., the RfC). For a given HAP, exposures at or below the reference level (HQ ≤ 1) are not likely to cause adverse health effects. As exposures increase above the reference level (HQs increasingly greater than 1), the potential for adverse effects increases. For exposures predicted to be above the RfC, the risk characterization includes the degree of confidence ascribed to the RfC values for the compound(s) of concern (i.e., high, medium, or low confidence) and discusses the impact of this on possible health interpretations.

The risk characterization for chronic effects other than cancer is developed using the HQ for inhalation, calculated for each HAP at each census block centroid. As discussed above, RfCs incorporate generally conservative uncertainty factors in the face of uncertain extrapolations, such that an HQ greater than 1 does not necessarily suggest the onset of adverse effects. The Hazard Index (HI) is the sum of hazard quotients for substances that affect the same target organ or organ system and is an approximation of the aggregate effect on a specific target organ (e.g., the lungs). The HQ and HI cannot be translated to a probability that adverse effects will occur, and it is unlikely to be proportional to adverse health effect outcomes in a population.

Screening for potentially significant acute inhalation exposures also follows the HQ approach. We divide the maximum estimated acute exposure by each available acute dose-response value to develop an array of HQs. In general, when none of these HQs is greater than one, there is no potential for acute risk. When one or more HQ is above 1, we evaluate additional information (e.g., proximity of the facility to potential exposure locations) to determine whether there is a potential for significant acute risks.

2.8.2 Mixtures

Since most or all receptors in these assessments receive exposures to multiple pollutants rather than a single pollutant, we estimate the aggregate health risks associated with exposure to all of the HAP from a particular source category.

To combine risks across multiple carcinogens, our assessments use the mixtures guidelines' default assumption of additivity of effects and combine risks by summing them using the independence formula in the mixtures guidelines (USEPA, 1986; USEPA, 2000b).

In assessing noncancer hazard from chronic exposures, in cases where different pollutants cause adverse health effects via completely different modes of action, it may be inappropriate to aggregate HQs. In consideration of these mode-of-action differences, the mixtures guidelines support aggregating effects of different substances in specific and limited ways. To conform to these guidelines, we aggregate noncancer HQs of HAP that act by similar toxic modes of action, or (where this information is absent) that affect the same target organ. This process creates, for each target organ, a target-organ-specific hazard index (TOSHI), defined as the sum of HQs for individual HAP that affect the same organ or organ system. For the RTRs, TOSHI calculations are based exclusively on effects occurring at the "critical dose" (i.e., the lowest dose that produces adverse health effects). Although HQs associated with some pollutants have been aggregated into more than one TOSHI, this has been done only in cases where the critical dose affects more than one target organ. Because impacts on organs or systems that occur above the critical dose have not been included in the TOSHI calculations, some TOSHIs may have been underestimated. As with the HQ, the TOSHI should not be interpreted as a probability of adverse effects or as strict delineation of "safe" and "unsafe" levels. Rather, the TOSHI is another measure of the potential for adverse health outcomes associated with pollutant exposure and needs to be interpreted carefully by health scientists and risk managers.

Because of the conservative nature of the acute inhalation screening assessment and the variable nature of emissions and potential exposures, acute impacts are screened on an individual pollutant basis, not using the TOSHI approach.

3 Risk results for the Coal- and Oil-Fired EGU source category

3.1 Source category description and emissions

This source category includes coal- and oil-fired electric utility steam generating units (EGUs) – or power plants – regulated under the MATS. Pursuant to the CAA, an EGU is "any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale [is] considered an electric utility steam generating unit." Coal- and oil-fired EGUs are the largest anthropogenic source of mercury emissions in the U.S. and also the largest source of hydrochloric acid, hydrofluoric acid and selenium. EGUs are also a major source of metallic HAP including arsenic, chromium, nickel, and others. The Coal- and Oil-Fired EGU source category is regulated under 40 CFR part 63, subpart UUUUU. A complete description of the Coal- and Oil-Fired EGU source category can be found in the text of the NPRM.

The emission estimates for this source category were obtained from two main sources: EPA's Air Markets Program Data[10] and EPA's WebFIRE[11] database that contains emissions factors for criteria and hazardous air pollutants (HAP) for industrial and non-industrial processes. We estimate that there are 323 facilities subject to the MATS operating in the U.S.[12] Emissions from the Coal- and Oil-Fired EGU source category are summarized in Table 3.1-1. The total HAP emissions from the source category are approximately 5,100 tons per year. The HAP emitted in the largest quantities are hydrochloric acid, hydrofluoric acid, selenium compounds, manganese compounds, nickel compounds and chromium compounds. Emissions of these 6 HAP make up over 99 percent of the total HAP emissions by mass. The PB-HAP reported as emissions from these facilities include lead compounds, arsenic compounds, mercury compounds, cadmium compounds, POM and dioxins. The following environmental HAP are emitted from the EGU facilities regulated under the MATS and are included in the environmental risk screening assessment: lead compounds, arsenic compounds, mercury compounds, cadmium compounds, POM, dioxins, hydrochloric acid and hydrofluoric acid.

The emissions for this source category are estimates of actual emissions on an annual basis. The risk results presented in the following sections are based on these actual emissions. MACT-allowable and facility-wide emissions were also estimated and the risk results based on those emissions are presented below as well. Details on the development of the actual and allowable emission estimates and the source of the data for this source category can be found in Appendix 1. Facility-wide emissions estimates include the same estimates of actual emissions for emissions sources in the source category, and emissions data from the 2014 NEI (version 2) for the sources outside the source category.

For the chronic inhalation risk assessment, the emissions inventory for the Coal- and Oil-Fired EGU source category includes emissions of 25 HAP with available chronic inhalation dose-response values. Of these, 15 are classified as known, probable, or possible carcinogens, with quantitative cancer dose-response values available and 22 HAP have quantitative noncancer dose-response values available. These HAP, their emissions and dose-response values are listed in Table 3.1-1 and the source of each dose-response value is listed in Appendix 8.

---

[10] https://ampd.epa.gov/ampd/

[11] https://cfpub.epa.gov/webfire/

[12] There are an estimated 323 facilities in the coal- and oil-fired EGU source category; however, one facility is located in Guam, which is beyond the geographic range of the model used to estimate risks. Therefore, the Guam facility was not modeled and the emissions for that facility are not included in this assessment.

For the acute inhalation risk assessment, for the Coal- and Oil-Fired EGU source category, maximum hourly emissions estimates were available, so we did not use the default emissions multiplier of 10 as described in Section 2.4. In general, maximum hourly emissions estimates were based on the maximum rated hourly heat input for each EGU. See Appendix 1 to this document for a detailed description of how the maximum hourly emissions were developed for this source category.

The emissions inventory for the Coal- and Oil-Fired EGU source category includes emissions of 7 HAP with relevant and available quantitative acute dose-response values. These HAP, their emissions and acute and chronic dose-response values are listed in Table 3.1-1 and the source of each dose-response value is listed in Appendix 8.

As mentioned previously, when we identify acute impacts which exceed their relevant dose-response values, we refine our acute screening estimates to the extent possible. For the Coal- and Oil-Fired EGU source category, the acute screening results indicate the peak emissions are considered unlikely to pose significant risk and further refinement was not warranted. The acute results for the source category are summarized in the following section and detailed information is contained in Appendix 10 to this document (*Detailed Risk Modeling Results*).

For the multipathway risk assessment, PB-HAP identified in the emissions inventory for the Coal- and Oil-Fired EGU source category include lead compounds, arsenic compounds, mercury compounds, cadmium compounds, polycyclic organic matter (POM) and dioxins. Of these, all but lead have quantitative chronic oral cancer or noncancer dose-response values available, which are presented in Table 3.1-1, and were screened for non-inhalation risks using a tiered screening approach described in Section 2.5. In evaluating the potential multipathway risks from emission of lead compounds, we compared maximum estimated chronic atmospheric concentrations with the current NAAQS for lead, also as described in Section 2.5. The results of the multipathway assessment for the source category are summarized in the following section and detailed information is contained in Appendix 10 to this document for the multipathway screening assessment and Appendix 11 of this document for the site-specific multipathway assessment.

For the environmental risk assessment, the PB-HAP identified above as well as two acid gases (hydrochloric acid and hydrofluoric acid) were screened for potential adverse environmental effects as described in Section 2.5. The benchmark values and a detailed discussion of the approach for this assessment can be found in Appendix 9. The results of the environmental assessment for the source category are summarized in the following section and detailed information is contained in Appendix 10 to this document.

Table 3.1-1 Summary of Emissions from the Coal- and Oil-Fired EGU source category and Dose-Response Values Used in the Residual Risk Assessment

HAP	Emissions (tpy)	Number of Facilities Reporting HAP (322 facilities in data set)	Prioritized Inhalation Dose-Response Value Identified by OAQPS			PB-HAP Oral Benchmark Values for Cancer (1/(mg/kg/d)) and/or Noncancer (mg/kg/d)[a]
			Unit Risk Estimate for Cancer (1/(μg/m³))	Reference Concentration for Noncancer (mg/m³)	Health Benchmark Values for Acute Noncancer (mg/m³)	
Hydrochloric Acid	2,797	322		0.02	2.1 (REL)	
Hydrofluoric Acid	2,034	322		0.014	0.24 (REL)	
Selenium Compounds	68	322		0.02		
Manganese Compounds	46	322		0.0003		
Nickel Compounds	39	322	0.00048	0.00009	e	
Chromium Compounds						
Chromium (III) Compounds	38	322				
Chromium (VI) Compounds	5	322	0.012	0.0001		
Lead Compounds	6	322		0.00015[d]		
Cobalt Compounds	6	322		0.0001		
Arsenic Compounds	5	322	0.0043	0.000015	0.0002 (REL)	1.5 (cancer)
Antimony Compounds	4	322		0.0002		
Mercury Compounds						
Mercury (elemental)	3	322		0.0003	0.0006 (REL)	c
Gaseous Divalent Mercury	0.6	322		0.0003		0.0001 (noncancer)
Particulate Divalent Mercury	0.04	322		0.0003		0.0001 (noncancer)
Formaldehyde	3	322	0.000013	0.0098	0.055 (REL)	
Cadmium Compounds	0.8	322	0.0018	0.00001	0.1 (AEGL-1 (1-hr))	0.001 (noncancer)
Naphthalene	0.7	322	0.000034	0.003		
Beryllium Compounds	0.4	322	0.0024	0.00002	0.025 (ERPG-2)	
Polycyclic Organic Matter						
Phenanthrene	0.1	322				b
2-methylnaphthalene	0.03	322	0.000048			0.05 (cancer)
Polychlorinated Biphenyls						
Pentachlorobiphenyl	0.004	322	0.0001			
Hexachlorobiphenyl	0.002	322	0.0001			
Dioxins/Furans						
1,2,3,4,6,7,8,9-octachlorodibenzo-p-dioxin	0.001	322	0.0099	0.00013		45 (cancer)

Table 3.1-1 Summary of Emissions from the Coal- and Oil-Fired EGU source category and Dose-Response Values Used in the Residual Risk Assessment

HAP	Emissions (tpy)	Number of Facilities Reporting HAP (322 facilities in data set)	Prioritized Inhalation Dose-Response Value Identified by OAQPS			PB-HAP Oral Benchmark Values for Cancer (1/(mg/kg/d)) and/or Noncancer (mg/kg/d)[a]
			Unit Risk Estimate for Cancer (1/(µg/m^3))	Reference Concentration for Noncancer (mg/m^3)	Health Benchmark Values for Acute Noncancer (mg/m^3)	
1,2,3,4,6,7,8,9-octachlorodibenzofuran	0.0003	322	0.0099	0.00013		45 (cancer)
1,2,3,4,6,7,8-heptachlorodibenzofuran	0.0003	322	0.33	0.000004		1500 (cancer)
1,2,3,4,6,7,8-heptachlorodibenzo-p-dioxin	0.0001	322	0.33	0.000004		1500 (cancer)
2,3,7,8-tetrachlorodibenzofuran	0.0001	322	3.3	0.0000004		15000 (cancer)

Notes:
[a] Benchmark values are provided only for PB-HAPs for which multipathway risk is assessed (via TRIM). There may be other PB-HAPs in this table, even though no benchmark is presented.
[b] IRIS has determined this POM to be not carcinogenic.
[c] The predominant form of mercury assessed in our multipathway risk screening assessment is methyl mercury, which is a transformation product of divalent mercury and accumulates in fish. While elemental mercury emissions can convert to divalent mercury in the atmosphere, such transformations generally occur beyond the 50 km modeling domain around the emissions sources in our assessment. *Emissions reported as "mercury compounds" is speciated into elemental, particulate divalent, and gaseous divalent and modeled accordingly in the multipathway screening assessment.
[d] There is no reference concentration for lead. In considering noncancer hazards for lead in this assessment, we compared rolling three-month average exposure estimates to the national ambient air quality standard (NAAQS) for lead (0.15 µg/m^3). The primary (health-based) standard is a maximum or not-to-be-exceeded, rolling three-month average, measured as total suspended particles (TSP). The secondary (welfare-based) standard is identical to the primary standard.
[e] Based on an in-depth examination of the available acute value for nickel [California EPA's acute (1-hour) REL], we have concluded that this value is not appropriate to use to support EPA's risk and technology review rules. This conclusion takes into account: the effect on which the acute REL is based; aspects of the methodology used in its derivation; and how this assessment stands in comparison to the ATSDR toxicological assessment, which considered the broader nickel health effects database. (79 FR 60247-8; October 6, 2014).

3.2 Baseline risk characterization

This section presents the results of the risk assessment for the Coal- and Oil-Fired EGU source category based on the modeling methods described in the previous sections. All baseline risk results are developed using the best estimates of actual HAP emissions summarized in the previous section. The basic chronic inhalation risk estimates presented here are the maximum individual lifetime cancer risk, the maximum chronic hazard index, and the cancer incidence. We also present results from our acute inhalation impact screening assessment in the form of maximum hazard quotients, as well as the results of our preliminary screening assessment for potential non-inhalation risks and environmental risk from PB-HAP.

Also presented are the HAP "drivers," which are the HAP that collectively contribute 90 percent of the maximum cancer risk or maximum hazard at the highest exposure location. A detailed summary of the facility-specific inhalation and multipathway risk assessment results is available in Appendix 10 of this document.

3.2.1 Risk assessment results based on actual emissions

Inhalation

Table 3.2-1 summarizes the chronic and acute inhalation risk results for this source category based upon baseline actual emissions. The estimated maximum lifetime individual cancer risk posed by the 322 facilities is 9-in-1 million, with nickel compounds from oil fuel sources as the major contributor to the risk. The total estimated cancer incidence from this source category is 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 193,000 people were estimated to have cancer risks at or above 1–in-1 million from HAP emitted from 4 of the 322 facilities in this source category. The estimated maximum chronic noncancer hazard index for the source category is 0.2 (respiratory) driven by emissions of nickel and cobalt compounds from oil fuel sources, and no one is exposed to a TOSHI above 1.

Worst-case acute HQs were calculated for every HAP that has an acute dose-response value, as shown in Table 3.1-1. Since no screening HQ was greater than 1, further refinement of the estimates was not warranted. Based on actual baseline emissions, the highest screening acute HQ of 0.09 (based on the acute REL for arsenic compounds) is shown in Table 3.2-2. No facilities are estimated to have an HQ (based on the REL, AEGL or an EPRG) greater than 1. Acute estimates for each plant and pollutant are provided in Appendix 10 of this document.

Table 3.2-1. Source Category Level Inhalation Risks for the Coal- and Oil-Fired EGU Source Category Based on Actual Emissions

Result		HAP "Drivers"
Facilities in Source Category		
Number of Facilities Estimated to be in Source Category	323	n/a
Number of Facilities Modeled in Risk Assessment	322	n/a
Cancer Risks		
Maximum Individual Lifetime Cancer Risk (in 1 million)	9	nickel compounds
Number of Facilities with Maximum Individual Lifetime Cancer Risk:		
Greater than or equal to 100-in-1 million	0	n/a
Greater than or equal to 10-in-1 million	0	n/a
Greater than or equal to 1-in-1 million	4	nickel compounds, arsenic compounds
Chronic Noncancer Risks		
Maximum Respiratory Hazard Index	0.2	nickel compounds, cobalt compounds
Number of Facilities with Maximum Respiratory Hazard Index:		
Greater than 1	0	n/a
Acute Noncancer Screening Results		
Maximum Acute Hazard Quotient	0.09	arsenic compounds (REL)
Number of Facilities With Potential for Acute Effects	0	
Population Exposure		
Number of People Living Within 50 Kilometers of Facilities Modeled	141,600,000	n/a
Number of People Exposed to Cancer Risk:		
Greater than or equal to 100-in-1 million	0	n/a
Greater than or equal to 10-in-1 million	0	n/a
Greater than or equal to 1-in-1 million	193,000	n/a
Number of People Exposed to Noncancer Respiratory Hazard Index:		
Greater than 1	0	n/a
Estimated Cancer Incidence (excess cancer cases per year)	0.04	n/a
Contribution of HAP to Cancer Incidence		
nickel compounds	47%	n/a
chromium (VI) compounds	37%	n/a
arsenic compounds	14%	n/a

Facility-wide Inhalation

The facility-wide chronic MIR and TOSHI, available in Appendix 10, are based on emissions from all sources at the identified facilities (both MACT and non-MACT sources). The results of the facility-wide assessment for cancer risks, as compared to the source category assessment, are summarized in Table 3.2-2. The results indicate that 9 facilities have a facility-wide cancer MIR greater than or equal to 1-in-1 million. The maximum facility-wide cancer MIR is 9-in-1 million, mainly driven by nickel compounds from oil fuel sources. The total estimated cancer incidence from the whole facility is 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 203,000 people were estimated to have cancer risks at or above 1-in-1 million from exposure to HAP emitted from both MACT and non-MACT sources at 9 of the 322 facilities modeled in this source category. The maximum facility-wide TOSHI for the source category is estimated to be less than 1 (at 0.2 for the respiratory HI), mainly driven by emissions of nickel and cobalt compounds from oil fuel sources. No people are exposed to noncancer hazard index above 1, based on facility-wide emissions from the 322 facilities assessed for this source category.

Table 3.2-2 Source Category Contribution to Facility-Wide Cancer Risks Based on Actual Emissions

Mercury and Air Toxics Standards	Number of Facilities Binned by Facility-Wide MIR (in 1 million)				
Source Category MIR Contribution to Facility-Wide MIR	<1	1≤ MIR<10	10≤ MIR<100	≥ 100	**Total**
> 90%	252	4	0	0	256
50-90%	28	0	0	0	28
10-50%	22	0	0	0	22
< 10%	11	5	0	0	16
Total	313	9	0	0	322

Multipathway

Table 3.2-3 summarizes the multipathway risk results for this source category based on baseline actual emissions. The PB-HAP emitted by facilities in this source category include arsenic compounds, POM (of which PAH is a subset), lead compounds, cadmium compounds, mercury compounds, and dioxins. To identify potential multipathway health risks from PB-HAP other than lead, we first performed a tiered screening assessment (Tiers 1, 2, and 3) based on emissions of PB-HAP emitted from each facility in the source category (see section 2.5).

Of the 322 facilities included in this assessment, 307 facilities have reported emissions of carcinogenic PB-HAP (arsenic, dioxins and POM) that exceed a Tier 1 cancer screening value of 1 (maximum screening value of 1000), and 235 facilities have reported emissions of non-carcinogenic PB-HAP (mercury and cadmium) that exceed a Tier 1 screening value of 1 (maximum screening value of 20 for cadmium and 200 for mercury). Due to the theoretical construct of the screening model, these screening values are not directly translatable into estimates of risk or hazard quotients for these facilities; rather they indicate that the initial multipathway screening assessment does not rule out the potential for multipathway impacts of concern.

Table 3.2-3. Source Category Level Multipathway Screening Assessment Risk Results for the Coal- and Oil-Fired EGU source category

		Tiered Multipathway Maximum Screening Values (SV) SV (# facilities above SV = 1)			
		Tier 1	**Tier 2**		**Tier 3**
PB-HAP	**Facilities Emitting PB-HAP**	**Fisher and Farmer**	**Fisher**	**Gardener**	**Fisher and/or Gardener**
Carcinogens[a]					
Arsenic Compounds	322	1000 (297)	20 (89)	200 (196)	50
Dioxins as 2,3,7,8-TCDD	322	100 (278)	20 (117)	2 (1)	NA
Polycyclic Organic Matter as Benzo(a)pyrene TEQ	322	8E-5 (0)	2E-5 (0)	9E-7 (0)	NA
Arsenic + Dioxins + POM	322	1000 (307)	30 (162)	200 (199)	50
Non-carcinogens					
Cadmium Compounds	322	20 (69)	1 (0)	0.3 (0)	NA
Mercury Compounds	322	200 (235)	30 (144)	0.07 (0)	9

Notes:

[a] POM and dioxin emissions were normalized to BaP and 2,3,7,8-TCDD, respectively, for oral toxicity and modeled for environmental fate and transport.

For the PB-HAP and facilities that exceed a Tier 1 multipathway screening value of 1, we used facility site-specific information to refine some of the assumptions associated with the local area around the facilities. While maintaining the exposure assumptions, we refine the scenario to examine a subsistence fisher and a gardener separately to develop a Tier 2 screening value. (See Section 2.5 and Appendix 6 of this document for more information on the Tier 2 screening assessment.) The additional site-specific information included the land use around the facilities, the location of fishable lakes, and local wind direction and speed. Based on this Tier 2 screening assessment, 199 facilities exceed a Tier 2 cancer screening value of 1, with 2 facilities having Tier 2 cancer screening values that exceed 100 (maximum is 200). No facilities exceed a Tier 2 noncancer screening value of 1 for cadmium, and 144 facilities exceed a noncancer screening value of 1 for mercury (maximum is 30).

For a selected set of PB-HAP and facilities that exceed a Tier 2 multipathway screening value of 1, we conducted a Tier 3 multipathway screening assessment. We assessed the 2 facilities with Tier 2 cancer screening values greater than or equal to 100, and the four facilities with noncancer screening values for mercury greater than or equal to 20. Tier 3 has three individual stages, including lake, plume rise, and time-series assessments. (See Section 2.5 and Appendix 6 of this document for more information on Tier 3). We progressed through the plume rise stage of Tier 3 for the selected facilities, after which the highest cancer screening value fell to 50, and the highest noncancer screening value fell to 9 (mercury).

Because the highest Tier 3 cancer screening value is much lower than 100-in-1 million, and because we expect the actual risk to be lower than the screening value (site-specific assessments typically lower estimates by an order of magnitude), we did not perform further assessment for cancer.

An exceedance of a screening value in any of the tiers cannot be equated with a risk value or a hazard quotient (or hazard index). Rather, it represents a high-end estimate of what the risk or hazard may be. For example, a screening value of 2 for a non-carcinogen can be interpreted to mean that we are confident that the HQ would be lower than 2. Similarly, a screening value of 30 for a carcinogen means that we are confident that the risk is lower than 30-in-1 million. Our confidence comes from the conservative, or health-protective, assumptions encompassed in the screening tiers: we choose inputs from the upper end of the range of possible values for the influential parameters used in the screening tiers; and we assume that the exposed individual exhibits ingestion behavior that would lead to a high total exposure.

When tiered screening values for any facility indicate a potential health risk to the public, we can conduct a more refined multipathway assessment for a specific facility or facilities. A refined assessment replaces some of the assumptions made in the tiered screening with facility-specific information. Because the highest Tier 3 (plume rise) noncancer screening value is well above 1, and because the time-series stage of Tier 3 was unlikely to reduce that screening value to 1, we performed a site-specific multipathway assessment to assess the noncancer hazard from mercury. Several facilities were selected because of their close proximity, including Coal Creek near Underwood, ND (facility ID 8011011), Leland Olds near Stanton, ND (facility ID 8086311), and Milton R Young near Center, ND (facility ID 8087911). All three of these facilities have Tier 2 noncancer screening values greater than or equal to 20 for mercury, and two of them have Tier 3 plume rise screening values of 9, which is the highest estimated for any facility. We expect that the exposure scenarios we assessed are among the highest that might be encountered for other facilities in this source category. The protocol for developing the refined site-specific multipathway assessment is found in Appendix 7 and the data, assumptions, and results are presented in Appendix 11 of this document. In the site-specific assessment, we calculated an HQ of 0.06 for the hypothetical fisher scenario, specifically for children ages 1–2 years, which is the most impacted age group based on fish ingestion per body weight.

The refined site-specific multipathway assessment, as in the screening assessments, includes some hypothetical elements, namely the hypothetical human receptor (i.e., the fisher). It is important to note that even though the multipathway assessment has been conducted, no data exist to verify the existence of the hypothetical human receptor. The fisher scenario involves an individual who regularly consumes fish caught in freshwater lakes near the source of interest over the course of a 70-year lifetime. If the fisher scenario did not pass the screening, we evaluated hazards from each lake that was fished in the screening assessment, with the same adjustments to fish ingestion rates as used in the screening according to lake acreage and its assumed impact on fish productivity.

The screening values are not directly comparable to the risks or hazards from the refined site-specific assessment. This is due to differences in the exposure scenarios, including a combined fisher and farmer receptor in Tier 1 (as opposed to individual receptors in the Tier 2, Tier 3, and refined assessments), idealized watersheds in the screening that direct most or all deposited chemical into the lake or farm/garden soil (as opposed to a more site-specific watershed treatment in the refined assessment), idealized and constant meteorological conditions in the screening assessment (as opposed to site-specific, time-variable meteorology in the refined assessment), incomplete treatments of air dispersion and plume rise in the screening assessment, and properties of surface soil and surface water that tend to overestimate bioaccumulation in the screening assessment (as opposed to site-specific soil and water properties used, if available, in the refined assessment).

In evaluating the potential for multipathway effects from emissions of lead, modeled maximum annual lead concentrations were compared to the NAAQS for lead (0.15 µg/m3). Lead emissions were reported from all 322 facilities. Results of this assessment indicate that the NAAQS for lead would not be exceeded by any facility.

Environmental

We conducted a screening-level evaluation of the potential adverse environmental risks associated with emissions of the following environmental HAP for the Mercury and Air Toxics Standards source category: arsenic, cadmium, dioxins, hydrochloric acid, hydrofluoric acid, lead, mercury, and POMs.

An environmental screening assessment was conducted for PB-HAP. For the Tier 1 environmental screening assessment:

- POM emissions had no Tier 1 exceedances for any ecological benchmark.
- Table 3.2-4 summarizes the source category level environmental risk screening assessment PB-HAP results.
- Arsenic emissions had a Tier 1 exceedance for a surface soil threshold level for plant communities by a maximum SV of 2.
- Cadmium emissions had a Tier 1 exceedance for the following benchmarks: surface soil NOAEL for mammalian insectivores (shrew), surface soil NOAEL for avian ground insectivores (woodcock), fish (avian/piscivores) NOAEL (Merganser), and fish (avian/piscivores) GMATL (Merganser) by a maximum SV of 6.
- Dioxin emissions had a Tier 1 exceedance for a surface soil NOAEL (mammalian insectivores – shrew) by a maximum SV of 20.
- Divalent mercury emissions had Tier 1 exceedances for the following benchmarks: sediment threshold level, sediment probable effect level, surface soil threshold level (plant communities), and surface soil threshold level (invertebrate communities) by a maximum SV of 100.
- Methyl mercury emissions had Tier 1 exceedances for the following benchmarks: fish

(avian/piscivores) NOAEL (Merganser), fish (avian/piscivores) GMATL (Merganser), fish (mammalian piscivores) NOAEL (mink), surface soil NOAEL (mammalian insectivores – shrew), surface soil NOAEL for avian ground insectivores (woodcock), and surface soil threshold level (invertebrate communities) by a maximum SV of 100.

A Tier 2 screening assessment was performed for Arsenic, cadmium, dioxin, divalent mercury, and methyl mercury emissions.

- Arsenic, cadmium, and dioxin emissions had no Tier 2 exceedances for any ecological benchmark.
- Divalent mercury emissions for two facilities had Tier 2 exceedances of a sediment threshold level by a maximum SV of 2 at lake #35731. See Table X in Appendix 10 for more details.
- Methyl mercury emissions for two facilities had Tier 2 exceedances of a fish (avian/piscivores) NOAEL (Merganser) benchmark by a maximum SV of 2 at lake #35731. See Table X in Appendix 10 for more details.
- Methyl mercury emissions for two facilities had Tier 2 exceedances of a surface soil NOAEL for avian ground insectivores (woodcock) benchmark by a maximum SV of 2.

A Tier 3 screening assessment was performed for divalent mercury and methyl mercury to verify that lake #35731(See Table X in Appendix 10) is located off-site and is not a manmade industrial pond. Lake #35731 was found to be located on-site and is a manmade industrial pond, and therefore, was removed from the assessment. Therefore, after the Tier 3 assessment, the only environmental risk screen exceedance is for methyl mercury emissions from two facilities that had exceedances of a surface soil NOAEL for avian ground insectivores (woodcock) benchmark by a maximum SV of 2.

For lead, we did not estimate any exceedances of the secondary lead NAAQS.

For hydrochloric acid and hydrofluoric acid, each individual concentration (i.e., each off-site data point in the modeling domain) was below the ecological benchmarks for all facilities.

Table 3.2-4. Source Category Level Environmental Risk Screening Assessment PB-HAP Results for the Coal- and Oil-Fired EGU Source Category

PB-HAP	Ecological Endpoint	Benchmark Effect Level	TIER 1	TIER 2		TIER 3
			Max SV (# of facilities with SV >1)	Max SV (# of facilities with SV >1)	% Soil Area with SV >1 for Highest Facility	SV (# of facilities with SV >1)
Arsenic	Surface Soil	Threshold Level – Plant Community	2(1)	<1(0)	0%	NP
Cadmium	Surface Soil	NOAEL – Mammalian Insectivores (shrew)	6(9)	<1(0)	0%	NP
		NOAEL – Avian Ground Insectivores (woodcock	3(1)	<1(0)	0%	NP
	Fish – Avian Piscivores	NOAEL (merganser)	2(1)	<1(0)	NA	NP
		GMATL (merganser)	2(1)	<1(0)	NA	NP
Dioxins	Surface Soil	NOAEL – Mammalian Insectivores (shrew)	20(205)	<1(0)	8%	NP
Divalent Mercury	Sediment	Threshold Level	8(34)	2(2)	NA	<1(0)
		Probable Effect Level	2(1)	<1(0)	NA	NP
	Surface Soil	Threshold Level – Plant Community	30(114)	<1(0)	5%	NP
		Threshold Level – Invertebrate Community	100(199)	<1(0)	19%	NP
Methyl Mercury	Fish – Avian Piscivores	NOAEL (merganser)	9(39)	2(2)	NA	<1(0)
		GMATL (merganser)	4(9)	<1(0)	NA	NP
	Fish – Mammalian Piscivores	NOAEL (mink)	2(1)	<1(0)	NA	NP
	Surface Soil	NOAEL – Mammalian Insectivores (shrew)	20(95)	<1(0)	5%	NP
		NOAEL – Avian Ground Insectivores (woodcock	100(221)	2(2)	25%	NP
		Threshold Level – Invertebrate Community	2(1)	<1(0)	0%	NP

NA – Not Applicable
NP – Not performed
SV – Screening Value

3.2.2 Risk assessment results based on allowable emissions

Inhalation

Potential differences between actual emissions levels and the maximum emissions allowable under the MACT standards (i.e., MACT-allowable emissions) were also calculated for the facilities. See Appendix 1 of this document for a discussion of the estimation of the allowable emissions. Risk results from the inhalation risk assessment using the allowable emissions indicate that the estimated maximum lifetime individual cancer risk is 10-in-1 million with nickel compound emissions from oil fuel sources driving the risks, and that the maximum chronic noncancer TOSHI (respiratory) value is 0.4 with nickel and cobalt compound emissions from oil fuel sources driving the TOSHI. The total estimated cancer incidence from this source category considering allowable emissions is 0.1 excess cancer cases per year, or one excess case in every 10 years. Based on allowable emission rates approximately 636,000 people were estimated to have cancer risks at or above 1-in-1 million, with 300 of those people estimated to have cancer risks at or above 10-in-1 million. No people are estimated to have a noncancer hazard index above 1.

3.3 Post-control risk characterization

A post-control risk assessment was not performed for the Coal- and Oil-Fired EGU source category.

4 General discussion of uncertainties in the risk assessment

The uncertainties in virtually all of the RTR risk assessments can be divided into three areas: 1) uncertainties in the emission data sets, 2) exposure modeling uncertainties, and 3) uncertainties in the dose-response relationships. Uncertainties in the emission estimates and in the air quality models lead to uncertainty in air concentrations. Uncertainty in exposure modeling can arise due to uncertain activity patterns, the locations of individuals within a census tract, and the microenvironmental concentrations as reflected in the exposure model. Finally, uncertainty in the shape of the relationship between exposure and effects, the URE and the RfC, also contributes to uncertainties in the risk assessment. These three areas of uncertainty are discussed below.

4.1 Emissions inventory uncertainties

Although the development of the RTR emissions data set involves an extensive quality assurance/quality control process, the accuracy of emission values will vary depending on certain factors, for example, the source of the data, the degree to which data are incomplete or missing, the degree to which assumptions made to complete the data sets are accurate, and the extent to which there are errors in these emission estimates. The emission estimates used in the risk assessment generally are annual totals for certain years, and they do not reflect short-term fluctuations during the course of a year or variations from year to year.

For the acute effects screening assessment, therefore, in the absence of available specific estimates or measurements, we use estimates of peak hourly emission rates. These estimates typically are calculated by first estimating the average annual hourly emissions rates by evenly dividing the total annual emission rate from the inventory into the 8,760 hours of the year. An emission adjustment factor that is intended to account for emission fluctuations during normal facility operations is then applied to these average annual hourly emission rates. The adjustment factor can be based on actual fluctuations seen in the available emission data for sources in a category or on engineering judgment; in the absence of such information, a default factor is applied.

To prepare the emissions data set, EPA gathers the best available data on emissions, emission release parameters, and other relevant source category-specific parameters. EPA often begins with its National Emissions Inventory (NEI) database as the starting point for emission rates, emissions release characteristics, and locations of the emission release points for each facility in the source category. The NEI is a composite of emission measurements and estimates produced by state and local regulatory agencies, industry, and EPA. EPA's industry experts then review the data for consistency and completeness and conduct extensive quality assurance/quality control checks. Available information, which may include compliance data, information from project files, permits, and other sources regarding facilities and emission sources, are also incorporated into the data set. This additional information may be incorporated in addition to the NEI data or in place of the NEI data, depending on EPA's evaluation of the quality of the various sources of data. In order to fill data gaps, EPA may conduct a formal information collection request (ICR) under the authority of section 114 of the Clean Air Act to obtain current, complete emissions data and other data from the facility owners and operators associated with the source category under review.

Uncertainty in the emissions data set stems from data gaps, default assumptions, and the emission models used to develop emissions inventory estimates. A variety of methods, such as emission factors, material balances, engineering judgement, air permit information and source testing, are used to develop emission estimates. Other parameters that are part of the emissions data set, including facility location and emission point parameters, may also be a source of uncertainty. Some release point locations use an average facility location instead of the location of each specific unit within the facility. In some instances, default release point parameters may be in the inventory. Where fugitive release parameters are not available, default values are included. Another potential source of emission estimate uncertainty may be low or poor quality data (e.g., out-of-date parameter values). For more information on the uncertainties in the emission estimates for this source category see Appendix 1 *(Emissions Inventory Support Documents*) of this document.

4.2 Exposure modeling uncertainties

4.2.1 Inhalation exposure modeling

Although every effort is made to identify all of the relevant facilities and emission points, as well as to develop accurate estimates of the annual emission rates for all relevant HAP, the uncertainties in our emission inventory likely dominate the uncertainties in the exposure assessment. The ambient air modeling uncertainties are considered relatively small in comparison, since we are using EPA's refined local dispersion model with site-specific parameters and reasonably representative meteorology. If anything, the population exposure estimates are biased high by not accounting for short- or long-term population mobility and by not addressing processes like deposition, plume depletion, and atmospheric degradation. Additionally, estimates of maximum individual risk (MIR) contain uncertainty because they are derived at census block centroid locations rather than actual residences. This uncertainty is known to create potential underestimates and overestimates of the actual MIR values for individual facilities; however, overall, it is not thought to have a significant impact on the estimated MIR for a source category. We also do not factor in the possibility of a source closure occurring during the 70-year chronic exposure period, leading to a potential upward bias in both the MIR and population risk estimates. Nor do we factor in the possibility of population growth during the 70-year chronic exposure period, which could lead to a potential downward bias in both the MIR and population risk estimates. Finally, we do not factor in time an individual spends indoors.

We did not include the effects of human mobility on exposures in the assessment. Specifically, short-term mobility and long-term mobility between census blocks in the modeling domain were not considered. (Short-term mobility is movement from one micro-environment to another over the course of hours or days. Long-term mobility is movement from one residence to another over the course of a lifetime.) The approach of not considering short or long-term population mobility does not bias the estimate of the theoretical MIR (by definition), nor does it affect the estimate of cancer incidence because the total population number remains the same. It does, however, affect the shape of the distribution of individual risks across the affected population, shifting it toward higher estimated individual risks at the upper end and reducing the number of people estimated to be at lower risks, thereby increasing the estimated number of people at specific high risk levels (e.g., 1-in-10 thousand or 1-in-1 million).

In addition, the assessment predicted the chronic exposures at the centroid of each populated census block as surrogates for the exposure concentrations for all people living in that block. Using the census block centroid to predict chronic exposures tends to over-predict exposures for people in the census block who live farther from the facility and under-predict exposures for people in the census block who live closer to the facility. Thus, using the census block centroid to predict chronic exposures may lead to a potential understatement or overstatement of the true maximum impact, but is an unbiased estimate of average risk and incidence. We reduce this uncertainty by analyzing large census blocks near facilities using aerial imagery and adjusting the location of the block centroid to better represent the population in the block, as well as adding additional receptor locations where the block population is not well represented by a single location.

The assessment evaluates the cancer inhalation risks associated with pollutant exposures over a 70-year period, which is the assumed lifetime of an individual. In reality, both the length of time that modeled emission sources at facilities actually operate (i.e., more or less than 70 years) and the domestic growth or decline of the modeled industry (i.e., the increase or decrease in the number or size of domestic facilities) will influence the future risks posed by a given source or source category. Depending on the characteristics of the industry, these factors will, in most cases, result in an overestimate both in individual risk levels and in the total estimated number of cancer cases. However, in the unlikely scenario where a facility maintains, or even increases, its emissions levels over a period of more than 70 years, residents live beyond 70 years at the same location, and the residents spend more of their days at that location, then the cancer inhalation risks could potentially be underestimated. However, annual cancer incidence estimates from exposures to emissions from these sources would not be affected by the length of time an emissions source operates.

The exposure estimates used in these analyses assume chronic exposures to ambient (outdoor) levels of pollutants. Because most people spend the majority of their time indoors, actual exposures may not be as high, depending on the characteristics of the pollutants modeled. For many of the HAP, indoor levels are roughly equivalent to ambient levels, but for very reactive pollutants or larger particles, indoor levels are typically lower. This factor has the potential to result in an overestimate of 25 to 30 percent of exposures (USEPA, 2001).

A sensitivity analysis, discussed in "Risk and Technology Review (RTR) Risk Assessment Methodologies" (USEPA 2009a), found that the selection of the meteorology data set location could have an impact on the risk estimates. The analysis found that cancer MIR derived using different meteorological stations varied by as much as 63 percent below to 51 percent above the value derived using the nearest meteorological station. Cancer incidence estimated using different meteorological stations varied by as much as 68 percent below to 120 percent above the value estimated using the nearest meteorological station. Similarly, air concentrations estimated using different meteorological stations varied by as much as 49 percent below to 21 percent above the value estimated using the nearest meteorological station. Since this analysis was performed EPA has increased the number of meteorological stations used in our risk assessments; thus, we expect variability to be reduced.

For the acute screening assessment, the results are intentionally biased high, and thus health-protective, by assuming the co-occurrence of independent factors, such as hourly emission rates, meteorology and human activity patterns. Furthermore, in cases where multiple acute dose-response values for a pollutant are considered scientifically acceptable, we choose the most conservative of these dose-response values, erring on the side of overestimating potential health risks from acute exposures. In cases where these results indicate the potential for exceeding acute HQs, we refine our assessment by developing a better understanding of the geography of the facility relative to potential exposure locations.

4.2.2 Multipathway exposure modeling

In modeling the fate and transport of pollutants through the environment and the non-inhalation exposure (i.e., ingestion) to these pollutants, TRIM.FaTE uses simplified representations of many complex real-world processes. This simplified representation introduces uncertainty. Uncertainties arise from model assumptions and structure, as reflected in the algorithms that describe the environmental movement of pollutants, and in the input values for numerous environmental parameters.

Uncertainty in the algorithms is inherent to any model attempting to represent complex processes in the real world. How persistent, bioaccumulative chemicals such as mercury, cadmium, arsenic, PAHs, and dioxins behave in the environment is highly complex, and many natural processes are represented in a simplified manner by TRIM.FaTE, including, for example:

- gaseous and particulate deposition from air;
- biogeochemical cycling in the aquatic environment, particularly mercury transformations through methylation and demethylation at the sediment-surface interface;
- mixing processes in air, water, and sediment;
- suspended and benthic sediment dynamics in lakes; and
- biotic processes such as growth, reproduction, and predation.

Even though some processes, such as diffusion, are known to follow second-order dynamics, the TRIM.FaTE model represents all fate and transport processes in terms of first-order differential equations. TRIM.FaTE also does not explicitly deal with lateral or vertical dispersion in the air compartments. Some algorithms, such as those addressing methylation and sediment transport, for example, do not consider all of the factors known to affect the process. Biotic processes including chemical absorption, chemical elimination, growth, reproduction, predation, and death have been represented relatively simplistically in the model. Although the model's algorithms have been validated and are based on professional judgment, some level of uncertainty results from such simplifications.

The input values for parameters are also associated with uncertainty. Algorithms that describe the environmental movement of pollutants depend on numerous environmental parameters for which the values might be naturally variable and for which available data are often limited. Examples of parameters for which input values are variable and uncertain include aquatic food web structure (e.g., diet of each fish species), biokinetic parameters that influence bioaccumulation (e.g., assimilation efficiencies and elimination rates), topographic characteristics (e.g., lake depth, runoff rates, and erosion rates), meteorological parameters (e.g., evaporation and precipitation rates), chemical transformation rates (e.g., methylation and demethylation rates, in the case of mercury), and human exposure parameters (especially fish consumption rates).

For TRIM.FaTE modeling, we use central tendency values and combinations of values that would lead to estimates of reasonable maximum exposures to bound risk estimates. We have conducted analyses of the sensitivity of risk estimates to parameter input values. For those parameters to which the model is particularly sensitive, we have continued to collect additional data to better quantify the variability and distribution of input values.
A more comprehensive explanation of the uncertainties related to fate, transport, and exposure modeling using TRIM.FaTE is provided in Appendix 6 (*Technical Support Document for TRIM-Based Multipathway Tiered Screening Methodology for RTR)* of this report for the tiered assessments and Appendix 11 (*Site-Specific Human Health Multipathway Residual Risk Assessment Report)* of this report for a site-specific assessment if one was conducted.

4.2.3 Environmental risk screening assessment

For each source category, we generally rely on site-specific levels of environmental HAP emissions to perform an environmental screening assessment. The environmental screening assessment is based on the outputs from models that estimate environmental HAP concentrations. The same models, specifically the TRIM.FaTE multipathway model and the AERMOD air dispersion model, are used to estimate environmental HAP concentrations for both the human multipathway screening analysis and for the environmental screening analysis. Therefore, both screening assessments have similar modeling uncertainties. Two important types of uncertainty associated with the use of these models in RTR environmental screening assessments (and inherent to any assessment that relies on environmental modeling) are model uncertainty and input uncertainty.

Model uncertainty concerns whether the selected models are appropriate for the assessment being conducted and whether they adequately represent the movement and accumulation of environmental HAP emissions in the environment. For example, does the model adequately describe the movement of the pollutant through the soil? This type of uncertainty is difficult to quantify. However, based on feedback received from previous EPA SAB reviews and other reviews, we are confident that the models used in the screening assessments are appropriate and state-of-the-art for the environmental risk assessments conducted in support of our RTR analyses.

Input uncertainty is concerned with how accurately the models have been configured and parameterized for the assessment at hand. For Tier 1 of the environmental screening assessment for PB-HAP, we configured the models to avoid underestimating exposure and risk to reduce the likelihood that the results indicate the risks are lower than they actually are. This was accomplished by selecting upper-end values from nationally-representative datasets for the more influential parameters in the environmental model, including selection and spatial configuration of the area of interest, the location and size of any bodies of water, meteorology, surface water and soil characteristics, and structure of the aquatic food web. In Tier 1, we use the maximum facility-specific emissions for the PB-HAP (other than lead compounds, which were evaluated by comparison to the Secondary Lead NAAQS) that are included in the environmental screening assessment and each of the media when comparing to ecological benchmarks. This is consistent with the conservative design of the Tier 1 screening assessment. In Tier 2 of the environmental screening assessment for PB-HAP, we refine the model inputs to account for meteorological patterns in the vicinity of the facility versus using upper-end national values, and we identify the locations of water bodies near the facility location. By refining the screening approach in Tier 2 to account for local geographical and meteorological data, we decrease the likelihood that concentrations in environmental media are overestimated, thereby increasing the usefulness of the screening assessment. To better represent widespread impacts, the modeled soil concentrations are averaged in Tier 2 to obtain one average soil concentration value for each facility and for each PB-HAP. For PB-HAP concentrations in water, sediment, and fish tissue, the highest value for each facility for each pollutant is used.

For the environmental screening assessment for acid gases, we employ a single-tiered approach. We use the modeled air concentrations and compare those with ecological benchmarks.

For both Tiers 1 and 2 of the environmental screening assessment, our approach to addressing model input uncertainty is generally cautious. We choose model inputs from the upper end of the range of possible values for the influential parameters used in the models, and we assume that the exposed individual exhibits ingestion behavior that would lead to a high total exposure. This approach reduces the likelihood of not identifying potential risks for adverse environmental impacts.

4.3 Uncertainties in the dose-response relationships

In the sections that follow, separate discussions are provided on uncertainty associated with cancer potency factors and for noncancer reference values. Cancer potency values are derived for chronic (lifetime) exposures. Noncancer dose-response values are generally derived for chronic exposures (up to a lifetime) but may also be derived for acute (less than 24 hours), short-term (from 24 hours up to 30 days), and subchronic (30 days up to 10 percent of lifetime) exposure durations, all of which are derived based on an assumption of continuous exposure throughout the duration specified. For the purposes of assessing all potential health risks associated with the emissions included in an assessment, we rely on both chronic (cancer and noncancer) and acute (noncancer) dose-response values, which are described in more detail below.

Although every effort is made to identify peer-reviewed dose-response values for all HAP emitted by the source category included in an assessment, some HAP have no peer-reviewed values. Since exposures to these pollutants cannot be included in a quantitative risk estimate, an understatement of risk for these pollutants at estimated exposure levels is possible. To help alleviate this potential underestimate, where we conclude similarity with a HAP for which a dose-response assessment value is available, we use that value as a surrogate for the assessment of the HAP for which no value is available. To the extent use of surrogates indicates appreciable risk, we may identify a need to increase priority for a new IRIS assessment of that substance. We additionally note that, generally speaking, HAP of greatest concern due to environmental exposures and hazards are those for which dose-response assessments have been performed, reducing the likelihood of understating risk. Further, HAP not included in the quantitative assessment are assessed qualitatively and considered in the risk characterization that informs the risk management decisions, including with regard to consideration of HAP reductions achieved by various control options.

Additionally, chronic dose-response values for certain compounds included in the assessment may be under EPA IRIS review. In those cases, revised assessments may determine in the future that these pollutants are more or less potent than currently thought.

For a group of compounds that are unspeciated (e.g., glycol ethers), we conservatively use the most protective reference value of an individual compound in that group to estimate risk. Similarly, for an individual compound in a group (e.g., ethylene glycol diethyl ether) that does not have a specified reference value, we apply the most protective reference value from the other compounds in the group to estimate risk.

Cancer assessment

The discussion of dose-response uncertainties in the estimation of cancer risk below focuses on the uncertainties associated with the specific approach currently used by the EPA to develop cancer potency factors. In general, these same uncertainties attend the development of cancer potency factors by CalEPA, the source of peer-reviewed cancer potency factors used where EPA-developed values are not yet available. To place this discussion in context, we provide a quote from the EPA's *Guidelines for Carcinogen Risk Assessment* (herein referred to as *Cancer Guidelines*). (USEPA, 2005d) "The primary goal of EPA actions is protection of human health; accordingly, as an Agency policy, risk assessment procedures, including default options that are used in the absence of scientific data to the contrary, should be health protective." The approach adopted in this document is consistent with this approach as described in the *Cancer Guidelines*.

For cancer endpoints EPA usually derives an oral slope factor for ingestion and a unit risk value for inhalation exposures. These values allow estimation of a lifetime probability of developing cancer given long-term exposures to the pollutant. Depending on the pollutant being evaluated, EPA relies on both animal bioassay and epidemiological studies to characterize cancer risk. As a science policy approach, consistent with the *Cancer Guidelines*, EPA uses animal cancer bioassays as indicators of potential human health risk when other human cancer risk data are unavailable.

Extrapolation of study data to estimate potential risks to human populations is based upon EPA's assessment of the scientific database for a pollutant using EPA's guidance documents and other peer-reviewed methodologies. The EPA *Cancer Guidelines* describe the Agency's recommendations for methodologies for cancer risk assessment. EPA believes that cancer risk estimates developed following the procedures described in the *Cancer Guidelines* and outlined below generally provide an upper bound estimate of risk. That is, EPA's upper bound estimates represent a plausible upper limit to the true value of a quantity (although this is usually not a true statistical confidence limit). In some circumstances, the true risk could be as low as zero; however, in other circumstances the risk could also be greater.[13] When developing an upper bound estimate of risk and to provide risk values that do not underestimate risk, EPA generally relies on conservative default approaches.[14] EPA also uses the upper bound (rather than lower bound or central tendency) estimates in its

[13] The exception to this is the URE for benzene, which is considered to cover a range of values, each end of which is considered to be equally plausible, and which is based on maximum likelihood estimates.

[14] According to the NRC report Science and Judgment in Risk Assessment (NRC, 1994) "[Default] options are generic approaches, based on general scientific knowledge and policy judgment, that are applied to various elements of the risk-assessment process when the correct scientific model is unknown or uncertain." The 1983 NRC report Risk Assessment in the Federal Government: Managing the Process defined default option as "the option chosen on the basis of risk assessment policy that appears to be the best choice in the absence of data to the contrary" (NRC, 1983a, p. 63). Therefore, default options are not rules that bind the Agency; rather, the Agency may depart from them in evaluating the risks posed by a specific substance when it believes this to be appropriate. In keeping with EPA's goal of protecting public health and the environment, default assumptions are used to ensure that risk to chemicals is not underestimated (although defaults are not intended to overtly overestimate risk). See EPA 2004 An Examination of EPA Risk Assessment Principles and Practices, EPA/100/B-04/001.

assessments, although it is noted that this approach can have limitations for some uses (e.g. priority setting, expected benefits analysis).

Such health risk assessments have associated uncertainties, some which may be considered quantitatively, and others which generally are expressed qualitatively. Uncertainties may vary substantially among cancer risk assessments associated with exposures to different pollutants, since the assessments employ different databases with different strengths and limitations and the procedures employed may differ in how well they represent actual biological processes for the assessed substance. Some of the major sources of uncertainty and variability in deriving cancer risk values are described more fully below.

(1) The qualitative similarities or differences between tumor responses observed in experimental animal bioassays and those which would occur in humans are a source of uncertainty in cancer risk assessments. In general, EPA does not assume that tumor sites observed in an experimental animal bioassay are necessarily predictive of the sites at which tumors would occur in humans.[15] However, unless scientific support is available to show otherwise, EPA assumes that tumors in animals are relevant in humans, regardless of target organ concordance. For a specific pollutant, qualitative differences in species responses can lead to either under-estimation or over-estimation of human cancer risks.

(2) Uncertainties regarding the most appropriate dose metric for an assessment can also lead to differences in risk predictions. For example, the measure of dose is commonly expressed in units of mg/kg/d ingested or the inhaled concentration of the pollutant. However, data may support development of a pharmacokinetic model for the absorption, distribution, metabolism and excretion of an agent, which may result in improved dose metrics (e.g., average blood concentration of the pollutant or the quantity of agent metabolized in the body). Quantitative uncertainties result when the appropriate choice of a dose metric is uncertain or when dose metric estimates are themselves uncertain (e.g., as can occur when alternative pharmacokinetic models are available for a compound). Uncertainty in dose estimates may lead to either over or underestimation of risk.

(3) For the quantitative extrapolation of cancer risk estimates from experimental animals to humans, EPA uses scaling methodologies (relating expected response to differences in physical size of the species), which introduce another source of uncertainty. These methodologies are based on both biological data on differences in rates of process according to species size and empirical comparisons of toxicity between experimental animals and humans. For a particular pollutant, the quantitative difference in cancer potency between experimental animals and humans may be either greater than or less than that estimated by baseline scientific scaling predictions due to uncertainties associated with limitations in the test data and the correctness of scaled estimates.

(4) EPA cancer risk estimates, whether based on epidemiological or experimental animal data, are generally developed using a benchmark dose (BMD) analysis to estimate a dose at which

[15] Per the EPA Cancer Guidelines: “The default option is that positive effects in animal cancer studies indicate that the agent under study can have carcinogenic potential in humans.” and “Target organ concordance is not a prerequisite for evaluating the implications of animal study results for humans.”

there is a specified excess risk of cancer, which is used as the point of departure (or POD) for the remainder of the calculation. Statistical uncertainty in developing a POD using a benchmark dose (BMD) approach is generally addressed though use of the 95 percent lower confidence limit on the dose at which the specified excess risk occurs (the BMDL), decreasing the likelihood of understating risk. EPA has generally utilized the multistage model for estimation of the BMDL using cancer bioassay data (see further discussion below).

(5) Extrapolation from high to low doses is an important source of uncertainty in cancer risk assessment. EPA uses different approaches to low dose risk assessment (i.e., developing estimates of risk for exposures to environmental doses of an agent from observations in experimental or epidemiological studies at higher dose) depending on the available data and understanding of a pollutant's mode of action (i.e., the manner in which a pollutant causes cancer). EPA's *Cancer Guidelines* express a preference for the use of reliable, compound-specific, biologically-based risk models when feasible; however, such models are rarely available. The mode of action for a pollutant (i.e., the manner in which a pollutant causes cancer) is a key consideration in determining how risks should be estimated for low-dose exposure. A reference value is calculated when the available mode of action data show the response to be nonlinear (e.g., as in a threshold response). A linear low-dose (straight line from POD) approach is used when available mode of action data support a linear (e.g., nonthreshold) response or as the most common default approach when a compound's mode of action is unknown. Linear extrapolation can be supported by both pollutant-specific data and broader scientific considerations. For example, EPA's *Cancer Guidelines* generally consider a linear dose-response to be appropriate for pollutants that interact with DNA and induce mutations. Pollutants whose effects are additive to background biological processes in cancer development can also be predicted to have low-dose linear responses, although the slope of this relationship may not be the same as the slope estimated by the straight line approach.

EPA most frequently utilizes a linear low-dose extrapolation approach as a baseline science-policy choice (a "default") when available data do not allow a compound-specific determination. This approach is designed to not underestimate risk in the face of uncertainty and variability. EPA believes that linear dose-response models, when appropriately applied as part of EPA's cancer risk assessment process, provide an upper bound estimate of risk and generally provide a health protective approach. Note that another source of uncertainty is the characterization of low-dose nonlinear, non-threshold relationships. The National Academy of Sciences (NAS, 1994) has encouraged the exploration of sigmoidal type functions (e.g., log-probit models) in representing dose-response relationships due to the variability in response within human populations. Another National Research Council report (NRC, 2006) suggests that models based on distributions of individual thresholds are likely to lead to sigmoidal-shaped dose-response functions for a population. This report notes sources of variability in the human population: "One might expect these individual tolerances to vary extensively in humans depending on genetics, coincident exposures, nutritional status, and various other susceptibility factors..." Thus, if a distribution of thresholds approach is considered for a carcinogen risk assessment, application would depend on ability of modeling to reflect the degree of variability in response in human populations (as opposed to responses in bioassays with genetically more uniform rodents). Note also that low dose linearity in risk can arise for reasons separate from population variability: due to the nature of a mode of action and additivity of a chemical's effect on top of background chemical exposures and biological processes.

As noted above, EPA's current approach to cancer risk assessment typically utilizes a straight line approach from the BMDL. This is equivalent to using an upper confidence limit on the slope of the straight line extrapolation. The impact of the choice of the BMDL on bottom line risk estimates can be quantified by comparing risk estimates using the BMDL value to central estimate BMD values, although these differences are generally not a large contributor to uncertainty in risk assessment (Subramaniam et. al., 2006). It is important to note that earlier EPA assessments, including the majority of those for which risk values exist today, were generally developed using the multistage model to extrapolate down to environmental dose levels and did not involve the use of a POD. Subramaniam et. al. (2006) also provide comparisons indicating that slopes based on straight line extrapolation from a POD do not show large differences from those based on the upper confidence limit of the multistage model.

(6) Cancer risk estimates do not generally make specific adjustments to reflect the variability in response within the human population — resulting in another source of uncertainty in assessments. In the diverse human population, some individuals are likely to be more sensitive to the action of a carcinogen than the typical individual, although compound-specific data to evaluate this variability are generally not available. There may also be important life stage differences in the quantitative potency of carcinogens and, with the exception of the recommendations in EPA's Supplemental Cancer Guidance for carcinogens with a mutagenic mode of action, risk assessments do not generally quantitatively address life stage differences. However, one approach used commonly in EPA assessments that may help address variability in response is to extrapolate human response from results observed in the most sensitive species and sex tested, resulting typically in the highest URE which can be supported by reliable data, thus supporting estimates that are designed not to underestimate risk in the face of uncertainty and variability.

Chronic noncancer assessment

Chronic noncancer reference values represent chronic exposure levels that are intended to be health-protective. That is, EPA and other organizations, such as the Agency for Toxic substances and disease Registry (ATSDR), which develop noncancer dose-response values use an approach that is intended not to underestimate risk in the face of uncertainty and variability. When there are gaps in the available information, uncertainty factors (UFs) are applied to derive reference values that are intended to be protective against appreciable risk of deleterious effects. Uncertainty factors are commonly default values[16] (e.g., factors of 10 or 3)

[16] According to the NRC report *Science and Judgment in Risk Assessment* (NRC, 1994) "[Default] options are generic approaches, based on general scientific knowledge and policy judgment, that are applied to various elements of the risk-assessment process when the correct scientific model is unknown or uncertain." The 1983 NRC report *Risk Assessment in the Federal Government: Managing the Process* defined *default option* as "the option chosen on the basis of risk assessment policy that appears to be the best choice in the absence of data to the contrary" (NRC, 1983a, p. 63). Therefore, default options are not rules that bind the Agency; rather, the Agency may depart from them in evaluating the risks posed by a specific substance when it believes this to be

used in the absence of compound-specific data; where data are available, uncertainty factors may also be developed using compound-specific information. When data are limited, more assumptions are needed and more default factors are used. Thus, there may be a greater tendency to overestimate risk—in the sense that further study might support development of reference values that are higher (i.e., less potent) because fewer default assumptions are needed. However, for some pollutants it is possible that risks may be underestimated.

For noncancer endpoints related to chronic exposures, EPA derives a reference dose (RfD) for exposures via ingestion, and a reference concentration (RfC) for inhalation exposures. As stated in the IRIS Glossary, these values provide an estimate (with uncertainty spanning perhaps an order of magnitude) of daily oral exposure (RfD) or of a continuous inhalation exposure (RfC) to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. To derive values that are intended to be "without appreciable risk," EPA's methodology relies upon an uncertainty factor (UF) approach (USEPA, 1993b; USEPA, 1994b) which includes consideration of both uncertainty and variability.

EPA begins by evaluating all of the available peer-reviewed literature to determine noncancer endpoints of concern, evaluating the quality, strengths and limitations of the available studies. EPA typically chooses the relevant endpoint that occurs at the lowest dose, often using statistical modeling of the available data, and then determines the appropriate POD for derivation of the reference value. A POD is determined by (in order of preference): (1) a statistical estimation using the BMD approach; (2) use of the dose or concentration at which the toxic response was not significantly elevated (no observed adverse effect level—NOAEL); or (3) use of the lowest observed adverse effect level (LOAEL).

A series of downward adjustments using default UFs is then applied to the POD to estimate the reference value (USEPA, 2002b). While collectively termed "UFs", these factors account for a number of different quantitative considerations when utilizing observed animal (usually rodent) or human toxicity data in a risk assessment. The UFs are intended to account for: (1) variation in susceptibility among the members of the human population (i.e., inter-individual variability); (2) uncertainty in extrapolating from experimental animal data to humans (i.e., interspecies differences); (3) uncertainty in extrapolating from data obtained in a study with less-than-lifetime exposure (i.e., extrapolating from subchronic to chronic exposure); (4) uncertainty in extrapolating from a LOAEL in the absence of a NOAEL; and (5) uncertainty when the database is incomplete or there are problems with applicability of available studies. When scientifically sound, peer-reviewed assessment-specific data are not available, default adjustment values are selected for the individual UFs. For each type of uncertainty (when relevant to the assessment), EPA typically applies an UF value of 10 or 3 with the cumulative UF value leading to a downward adjustment of 10-3000 fold from the selected POD. An UF of 3 is used when the data do not support the use of a 10-fold factor. If

appropriate. In keeping with EPA's goal of protecting public health and the environment, default assumptions are used to ensure that risk to chemicals is not underestimated (although defaults are not intended to overtly overestimate risk). See EPA 2004 *An examination of EPA Risk Assessment Principles and Practices,* EPA/100/B-04/001.

an extrapolation step or adjustment is not relevant to an assessment (e.g., if applying human toxicity data and an interspecies extrapolation is not required) the associated UF is not used. The major adjustment steps are described more fully below.

1) Heterogeneity among humans is a key source of variability as well as uncertainty. Uncertainty related to human variation is considered in extrapolating doses from a subset or smaller-sized population, often of one sex or of a narrow range of life stages (typical of occupational epidemiologic studies), to a larger, more diverse population. In the absence of pollutant-specific data on human variation, a 10-fold UF is used to account for uncertainty associated with human variation. Human variation may be larger or smaller; however, data to examine the potential magnitude of human variability are often unavailable. In some situations, a smaller UF of 3 may be applied to reflect a known lack of significant variability among humans.

2) Extrapolation from results of studies in experimental animals to humans is a necessary step for the majority of chemical risk assessments. When interpreting animal data, the concentration at the POD (e.g. NOAEL, BMDL) in an animal model (e.g. rodents) is extrapolated to estimate the human response. While there is long-standing scientific support for the use of animal studies as indicators of potential toxicity to humans, there are uncertainties in such extrapolations. In the absence of data to the contrary, the typical approach is to use the most relevant endpoint from the most sensitive species and the most sensitive sex in assessing risks to the average human. Typically, compound specific data to evaluate relative sensitivity in humans versus rodents are lacking, thus leading to uncertainty in this extrapolation. Size-related differences (allometric relationships) indicate that typically humans are more sensitive than rodents when compared on a mg/kg/day basis. The default choice of 10 for the interspecies UF is consistent with these differences. For a specific chemical, differences in species responses may be greater or less than this value.

Pharmacokinetic models are useful to examine species differences in pharmacokinetic processing and associated uncertainties; however, such dosimetric adjustments are not always possible. Information may not be available to quantitatively assess toxicokinetic or toxicodynamic differences between animals and humans, and in many cases a 10-fold UF (with separate factors of 3 for toxicokinetic and toxicodynamic components) is used to account for expected species differences and associated uncertainty in extrapolating from laboratory animals to humans in the derivation of a reference value. If information on one or the other of these components is available and accounted for in the cross-species extrapolation, a UF of 3 may be used for the remaining component.

3) In the case of reference values for chronic exposures where only data from shorter durations are available (e.g., 90-day subchronic studies in rodents) or when such data are judged more appropriate for development of an RfC, an additional UF of 3 or 10-fold is typically applied unless the available scientific information supports use of a different value.

4) Toxicity data are typically limited as to the dose or exposure levels that have been tested in individual studies; in an animal study, for example, treatment groups may differ in exposure by up to an order of magnitude. The preferred approach to arrive at a POD is to use

BMD analysis; however, this approach requires adequate quantitative results for a meaningful analysis, which is not always possible. Use of a NOAEL is the next preferred approach after BMD analysis in determining a POD for deriving a health effect reference value. However, many studies lack a dose or exposure level at which an adverse effect is not observed (i.e., a NOAEL is not identified). When using data limited to a LOAEL, a UF of 10 or 3-fold is often applied.

5) The database UF is intended to account for the potential for deriving an underprotective RfD/RfC due to a data gap preventing complete characterization of the chemical's toxicity. In the absence of studies for a known or suspected endpoint of concern, a UF of 10 or 3-fold is typically applied.

Acute noncancer assessment

Many of the UFs used to account for variability and uncertainty in the development of acute reference values are quite similar to those developed for chronic durations. For acute reference values, though, individual UF values may be less than 10. UFs are applied based on chemical- or health effect-specific information or based on the purpose of the reference value. The UFs applied in acute reference value derivation include: 1) heterogeneity among humans; 2) uncertainty in extrapolating from animals to humans; 3) uncertainty in LOAEL to NOAEL adjustments; and 4) uncertainty in accounting for an incomplete database on toxic effects of potential concern. Additional adjustments are often applied to account for uncertainty in extrapolation from observations at one exposure duration (e.g., 4 hours) to arrive at a POD for derivation of an acute reference value at another exposure duration (e.g., 1 hour).

Not all acute dose-response values are developed for the same purpose and care must be taken when interpreting the results of an acute assessment of human health effects relative to the reference value or values being exceeded. Where relevant to the estimated exposures, the lack of dose-response values at different levels of severity should be factored into the risk characterization as potential uncertainties.

Environmental Risk Screening Assessment

Uncertainty also exists in the ecological benchmarks for the environmental risk screening assessment. We established a hierarchy of preferred benchmark sources to allow selection of benchmarks for each environmental HAP at each ecological assessment endpoint. In general, EPA benchmarks used at a programmatic level (e.g., Office of Water, Superfund Program) were used if available. If not, we used EPA benchmarks used in regional programs (e.g., Superfund Program). If benchmarks were not available at a programmatic or regional level, we used benchmarks developed by other agencies (e.g., NOAA) or by state agencies.

In all cases (except for lead compounds, which were evaluated through a comparison to the NAAQS), we searched for benchmarks at the following three effect levels, as described in Section 2.6 of this report and in Appendix 9 (*Environmental Risk Screening Assessment*) of this report: a no-effect level (i.e., NOAEL), threshold-effect level (i.e., LOAEL), and probable-effect level (i.e., PEL).

For some ecological assessment endpoint/environmental HAP combinations, we could identify benchmarks for all three effect levels, but for most we could not. In one case, where different agencies derived significantly different numbers to represent a threshold for effect, we included both. In several cases, only a single benchmark was available. In cases where multiple effect levels were available for a particular PB-HAP and assessment endpoint, we used all of the available effect levels to help us determine whether risk exists if risks could be considered significant and widespread.

5 References

Allen, et al., 2004. Variable Industrial VOC Emissions and their impact on ozone formation in the Houston Galveston Area. Texas Environmental Research Consortium. https://www.researchgate.net/publication/237593060_Variable_Industrial_VOC_Emissions_and_their_Impact_on_Ozone_Formation_in_the_Houston_Galveston_Area

ATSDR, 2012. Agency for Toxic Substances & Disease Registry Toxicological Profile for Manganese. http://www.atsdr.cdc.gov/toxprofiles/tp.asp?id=102&tid=23

ATSDR, 2018a. Agency for Toxic Substances & Disease Registry Toxicological Profile for Nickel. https://www.atsdr.cdc.gov/toxprofiles/tp.asp?id=245&tid=44

ATSDR, 2018b. Agency for Toxic Substances and Disease Registry (ATSDR) Toxic Substances Portal. Minimal Risk Levels (MRLs). http://www.atsdr.cdc.gov/mrls/index.asp

Burger, J. 2002. Daily consumption of wild fish and game: Exposures of high end recreationalists. Environmental Health Research. 12(4):343–354.

CalEPA, 2008. California Environmental Protection Agency. Technical Support Document For the Derivation of Noncancer Reference Exposure Levels. https://oehha.ca.gov/media/downloads/crnr/appendixd1final.pdf

Dorman DC, Struve MF, Wong BA, Marshall MW, Gross EA and Willson GA, 2008. Respiratory tract responses in male rats following subchronic acrolein inhalation. Inhal Toxicol 20(3): 205-16.

Feron VJ, Kryusse A, Til HP, et al., 1978. Repeated exposure to acrolein vapor: subacute studies in hamsters, rats and rabbits. Toxicology 9:47-57.

Grimsrud TK and Andersen A., 2010. Evidence of carcinogenicity in humans of water-soluble nickel salts. J Occup Med Toxicol 2010, 5:1-7. Available online at http://www.occup-med.com/content/5/1/7

Herr, D.W., Graff, J.E., Moser, V.C., Crofton, K.M., Little, P.B., Morgan, D.L., and Sills, R.C., 2007. Inhalational exposure to carbonyl sulfide produced altered brainstem auditory and somatosensory-evoked potentials in Fischer 344N rats. Toxicol. Sci. 95(1):118-135, 2007.

IARC, 1990. International Agency for Research on Cancer, 1990. IARC monographs on the evaluation of carcinogenic risks to humans. Chromium, nickel, and welding. Vol. 49. Lyons, France: International Agency for Research on Cancer, World Health Organization Vol. 49:256.

Morgan, D.L., Little, P.B., Herr, D.W., Moser, V.C., Collins, B., Herbert, R., Johnson, G.A., Maronpot, R.R., Harry, G.J., and Sills, R.C., 2004. Neurotoxicity of carbonyl sulfide in F344 rats following inhalation exposure for up to 12 weeks. Toxicol. Appl. Pharmacol. 200(2):131-145, 2004.

National Academy of Sciences, 1994. National Research Council. Science and Judgement in Risk Assessment. Washington, DC: National Academy Press.

NRC, 2006. National Research Council. Assessing the Human Health Risks of Trichloroethylene. National Academies Press, Washington DC.

NTP, 2016. National Toxicology Program. 2016. Report on Carcinogens, Fourteenth Edition.; Research Triangle Park, NC: U.S. Department of Health and Human Services, Public Health Service. https://ntp.niehs.nih.gov/pubhealth/roc/index-1.html

OEHHA, 2015. California Office of Environmental Health Hazard Assessment. All Acute Reference Exposure Levels developed by OEHHA as of June 2014. http://oehha.ca.gov/air/allrels.html

OMB, 2007. Memorandum for the Heads of Executive Departments and Agencies - Updated Principles for Risk Analysis (September 19, 2007), from Susan E. Dudley, Administrator, Office of Information and Regulatory Affairs, Office of Management and Budget; and Sharon L. Hays, Associate Director and Deputy Director for Science, Office of Science and Technology Policy. https://georgewbush-whitehouse.archives.gov/omb/memoranda/fy2007/m07-24.pdf

R.P. Subramaniam, P. White and V.J. Cogliano. 2006. Comparison of cancer slope factors using different statistical approaches, Risk Anal. Vol 26, p. 825-830.

Roels HA, Ghyselen P, Buchet JP, et al. 1992. Assessment of the permissible exposure level to manganese in workers exposed to manganese dioxide dust. Br J Ind Med 49:25-34.

Sills, R.C., Morgan, D.L., Herr, D.W., Little, P.B., George, N.M., Ton, T.V., Love, N.E., Maronpot, R.R., and Johnson, G.A., 2004. Contribution of magnetic resonance microscopy in the 12-week neurotoxicity evaluation of carbonyl sulfide in Fischer 344 rats. Toxicol. Pathol. 32:501-510, 2004.

USEPA, 1986. Guidelines for the Health Risk Assessment of Chemical Mixtures. EPA-630-R-98-002. https://www.epa.gov/risk/guidelines-health-risk-assessment-chemical-mixtures

USEPA, 1993a. Integrated Risk Information system Review of Manganese. https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=373

USEPA, 1993b. Reference Dose (RfC): Description and Use in Health Risk Assessments. https://www.epa.gov/iris/reference-dose-rfd-description-and-use-health-risk-assessments

USEPA, 1994a. US Environmental Protection Agency. Methods for Derivation of Inhalation Reference Concentrations and Application of Inhalation Dosimetry. EPA/600/8-90/066F. Office of Research and Development. Washington, DC: U.S.EPA.

USEPA, 1994b. Methods for Derivation of Inhalation Reference Concentrations and Application of Inhalation Dosimetry. https://www.epa.gov/risk/methods-derivation-inhalation-reference-concentrations-and-application-inhalation-dosimetry

USEPA, 1999. Residual Risk Report to Congress. 453R-99-001. https://www3.epa.gov/airtoxics/rrisk/risk_rep.pdf

USEPA, 2000a. Risk Characterization Handbook. EPA 100-B-00-002. https://www.epa.gov/sites/production/files/2015-10/documents/osp_risk_characterization_handbook_2000.pdf

USEPA, 2000b. Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. EPA-630/R-00-002. https://cfpub.epa.gov/ncea/risk/recordisplay.cfm?deid=20533

USEPA, 2001. National-Scale Air Toxics Assessment for 1996. EPA 453/R–01–003. January 2001. page 85.

USEPA, 2002a. EPA's Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by the Environmental Protection Agency. EPA Office of Environmental Information. EPA/260R-02-008. https://www.epa.gov/quality/guidelines-ensuring-and-maximizing-quality-objectivity-utility-and-integrity-information

USEPA, 2002b. A Review of the Reference Dose and Reference Concentration Processes. https://www.epa.gov/osa/review-reference-dose-and-reference-concentration-processes

USEPA, 2003. Integrated Risk Information System Review of Acrolein. https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=364

USEPA, 2005a. Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions; Final Rule. 40 CFR Part 51. https://www3.epa.gov/scram001/guidance/guide/appw_05.pdf

USEPA, 2005b. Supplemental guidance for assessing early-life exposure to carcinogens. EPA/630/R-03003F. https://www3.epa.gov/ttn/atw/childrens_supplement_final.pdf

USEPA, 2005c. Science Policy Council Cancer Guidelines Implementation Workgroup Communication I: Memo from W.H. Farland dated 4 October 2005 to Science Policy Council. https://www.epa.gov/sites/production/files/2015-01/documents/cgiwgcommuniation_i.pdf

USEPA, 2005d. Guidelines for Carcinogen Risk Assessment. U.S. Environmental Protection Agency, Washington, DC, EPA/630/P-03/001F. https://www.epa.gov/risk/guidelines-carcinogen-risk-assessment

USEPA, 2006. Performing risk assessments that include carcinogens described in the Supplemental Guidance as having a mutagenic mode of action. Science Policy Council Cancer Guidelines Implementation Workgroup Communication II: Memo from W.H. Farland dated 14 June 2006. https://www.epa.gov/sites/production/files/2015-01/documents/cgiwg-communication_ii.pdf

USEPA, 2009a. Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies – MACT I Petroleum Refining Sources and Portland Cement Manufacturing. EPA-452/R-09-006. https://cfpub.epa.gov/si/si_public_record_report.cfm?dirEntryID=238928

USEPA, 2009b. Graphical Arrays of Chemical-Specific Health Effect Reference Values for Inhalation Exposures [Final Report]. EPA/600/R-09/061, 2009. http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=211003

USEPA, 2010a. SAB's Response to EPA's RTR Risk Assessment Methodologies. https://yosemite.epa.gov/sab/sabproduct.nsf/0/b031ddf79cffded38525734f00649caf!OpenDocument&TableRow=2.3#2

US EPA, 2010b. Memorandum from Dave Guinnup to Docket EPA-HQ-OAR-2010-0600, entitled, "EPA's Actions in Response to Key Recommendations of the SAB Review of RTR Risk Assessment Methodologies". https://yosemite.epa.gov/sab/sabproduct.nsf/3BE2C36A4ADDC85A85257B48006C88D7/$File/EPA+resp+to+SAB+on+RTR+memo.pdf

USEPA, 2011. Exposure Factors Handbook: 2011 Edition (Final). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-09/052F. https://cfpub.epa.gov/ncea/risk/recordisplay.cfm?deid=236252

USEPA, 2014a. Table 1. Prioritized Chronic Dose-Response Values (5/9/14). Office of Air Quality Planning and Standards. https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants

USEPA, 2014b. Table 2. Acute Dose-Response Values for Screening Risk Assessments (9/18/2014). Office of Air Quality Planning and Standards. https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants

USEPA, 2018a User's Guide for the AMS/EPA Regulatory Model (AERMOD). EPA-454/B-18-001, U.S. Environmental Protection Agency, Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/models/aermod/aermod_userguide.pdf

USEPA, 2018b. AERMOD Implementation Guide. EPA-454/B-18-003, U.S. Environmental Protection Agency, Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/models/aermod/aermod_implementation_guide.pdf

WHO, 1991. World Health Organization and the European Union's Scientific Committee on Health and Environmental Risks (SCHER, 2006).

Appendix 10
Detailed Risk Modeling Results

Table 1 - Facility Identification Information

Facility NEI ID	Facility Name	Address	City	State	County
280737154411	R D Morrow Senior Generating Plant	304 Old Okahola Schoolhouse Road	Purvis	MS	Lamar County
290716032111	Labadie	LABADIE BOTTOM ROAD	LABADIE	MO	Franklin County
290777496411	John Twitty Energy Center	5100 WEST FARM ROAD 164	SPRINGFIELD	MO	Greene County
290837529611	Montrose	400 SW HIGHWAY P	CLINTON	MO	Henry County
290957663711	Hawthorn	8700 HAWTHORN ROAD	KANSAS CITY	MO	Jackson County
290957664111	Sibley	33200 EAST JOHNSON RD	SIBLEY	MO	Jackson County
290975321511	Asbury	21133 UPHILL LANE	ASBURY	MO	Jasper County
290995258811	Rush Island	HWY 61 AT AA VIA BIG HOLLOW RD	FESTUS	MO	Jefferson County
291435363811	New Madrid Power Plant	41 ST. JUDE ROAD	MARSTON	MO	New Madrid County
291656795111	Iatan	20250 HIGHWAY 45 NORTH	WESTON	MO	Platte County
291756688411	Thomas Hill Energy Center	5693 HWY F	CLIFTON HILL	MO	Randolph County
291836783411	Sioux	HWY 94	WEST ALTON	MO	St. Charles County
291896816611	Meramec	8200 FINE RD	ST. LOUIS	MO	St. Louis County
292017595411	Sikeston	1551 W WAKEFIELD ST	SIKESTON	MO	Scott County
300037851511	Hardin Generating Station	SUGAR FACTORY RD	HARDIN	MT	Big Horn County
300837618511	Lewis & Clark	MT HWY 23	SIDNEY	MT	Richland County
300877765611	Colstrip	WILLOW AVENUE	COLSTRIP	MT	Rosebud County
300877854911	Colstrip Energy Limited Partnership	ROSEBUD PLANT	COLSTRIP	MT	Rosebud County
301115270711	Yellowstone Energy Limited Partnership	2215 N FRONTAGE RD	BILLINGS	MT	Yellowstone County
310018399211	Gerald Whelan Energy Center	4520 E South St	Hastings	NE	Adams County
310537766111	Lon D Wright Power Plant	2701 E 1st St	Fremont	NE	Dodge County
310556732411	North Omaha Station	7475 Pershing Drive	Omaha	NE	Douglas County
310798212011	Platte	1035 W Wildwood Dr	Grand Island	NE	Hall County
311095281111	Sheldon	4500 W Pella Rd	Hallam	NE	Lancaster County
311117766511	Gerald Gentleman Station	6089 S Highway 25	Sutherland	NE	Lincoln County
311317303711	Nebraska City Station	7264 L Rd	Nebraska City	NE	Otoe County
3201112758911	TS Power Plant	3 mi North of Dunphy	DUNPHY	NV	Eureka County
320137302011	North Valmy	North of I80 Stonehouse Int 212	VALMY	NV	Humboldt County
330138178911	Merrimack	431 RIVER ROAD	BOW	NH	Merrimack County
330157287811	Schiller	400 GOSLING ROAD	PORTSMOUTH	NH	Rockingham County
330157288011	Newington	165 GOSLING ROAD	NEWINGTON	NH	Rockingham County
340095133011	B L England	900 NORTH SHR RD	BEESLEY'S POINT	NJ	Cape May County
340158093811	Logan Generating Plant	76 RT 130	SWEDESBORO	NJ	Gloucester County
340337989011	Carneys Point	500 SHELL RD	CARNEYS POINT	NJ	Salem County
350315597111	Escalante	County Road 19	Prewitt	NM	McKinley County
350457197711	Four Corners Steam Elec Station	US 550	Fruitland	NM	San Juan County
350457991911	San Juan	6800 N County Road	Waterflow	NM	San Juan County
360637417811	Somerset Operating Company (Kintigh)	7725 LAKE RD	BARKER	NY	Niagara County
360718427811	Roseton Generating LLC	992 RIVER RD	NEWBURGH	NY	Orange County
360757980511	Oswego Harbor Power	261 WASHINGTON BLVD	OSWEGO	NY	Oswego County
360818309011	Ravenswood Generating Station	38-54 VERNON BLVD	QUEENS	NY	Queens County
361098542611	Cayuga Operating Company, LLC	228 CAYUGA DR	LANSING	NY	Tompkins County
370218392811	Asheville	200 CP&L Drive	Arden	NC	Buncombe County
370358370411	Marshall	8320 East NC Hwy 150	Terrell	NC	Catawba County
370458300611	Cliffside	573 Duke Power Road (SR 1002)	Mooresboro	NC	Cleveland County
370658124311	Edgecombe Genco, LLC	6358 Old Battleboro Road	Battleboro	NC	Edgecombe County
370718137511	G G Allen	253 Plant Allen Rd.	Belmont	NC	Gaston County

Table 2a – Maximum Predicted HEM-3 Chronic Risks
Actual Emissions

	Category Chronic Risk [1]				Facility Chronic Risk [1]			
Facility NEI ID	Cancer MIR	Cancer Incidence	Noncancer Max HI	Target Organ	Cancer MIR	Noncancer Max HI	Target Organ	SC % of Facility-wide Cancer Risk
261396336811	6.97E-09	7.67E-06	8.91E-05	respiratory	7.03E-09	8.94E-05	respiratory	99%
261398125511	4.48E-09	1.25E-05	4.51E-05	respiratory	4.53E-09	4.59E-05	respiratory	99%
261477239111_1	3.66E-08	6.30E-05	1.99E-04	skeletal	3.66E-08	1.99E-04	skeletal	100%
261477239111_2	4.13E-08	1.28E-04	2.20E-04	skeletal	4.13E-08	2.20E-04	skeletal	100%
261637422511	8.92E-08	7.33E-04	3.39E-04	respiratory	8.97E-08	3.41E-04	respiratory	99%
261638229311	1.86E-08	1.76E-04	8.85E-05	skeletal	1.92E-08	8.85E-05	skeletal	97%
270317039811	8.05E-08	5.57E-07	3.17E-04	respiratory	8.05E-08	3.17E-04	respiratory	100%
270616173211	2.62E-08	7.45E-06	1.72E-04	respiratory	2.63E-08	1.73E-04	respiratory	100%
271117072311	8.81E-09	1.21E-06	4.27E-05	skeletal	9.31E-09	4.27E-05	skeletal	95%
271416990811	3.11E-08	8.78E-05	1.14E-04	respiratory	3.12E-08	1.14E-04	respiratory	100%
271636772111	1.20E-08	3.89E-05	1.20E-04	respiratory	1.23E-08	1.21E-04	respiratory	98%
280197053011	8.63E-08	2.34E-05	7.24E-04	developmental	8.62E-08	7.22E-04	developmental	100%
280596251011	1.47E-08	1.32E-05	5.72E-05	respiratory	8.95E-08	1.39E-03	kidney	16%
280737154411	2.29E-08	5.23E-06	7.91E-05	developmental	9.49E-07	2.34E-02	neurological	2%
290716032111	2.50E-07	1.44E-03	9.16E-04	respiratory	2.54E-07	9.34E-04	respiratory	98%
290777496411	1.57E-08	8.48E-06	2.06E-04	skeletal	1.60E-08	2.09E-04	skeletal	98%
290837529611	1.11E-08	1.61E-06	4.27E-05	respiratory	1.11E-08	4.27E-05	respiratory	100%
290957663711	6.64E-09	2.14E-05	9.09E-05	respiratory	8.15E-09	1.06E-04	respiratory	81%
290957664111	5.09E-08	1.35E-04	1.82E-04	developmental	5.09E-08	1.82E-04	developmental	100%
290975321511	6.04E-09	1.44E-06	9.36E-05	respiratory	6.04E-09	9.36E-05	respiratory	100%
290995258811	8.85E-08	2.00E-04	3.65E-04	respiratory	8.87E-08	3.66E-04	respiratory	100%
291435363811	4.79E-08	2.17E-05	1.71E-04	developmental	4.79E-08	1.71E-04	developmental	100%
291656795111	2.05E-08	2.57E-05	1.54E-04	respiratory	2.05E-08	1.54E-04	respiratory	100%
291756688411	3.34E-08	8.63E-06	1.83E-04	skeletal	3.36E-08	1.84E-04	skeletal	99%
291836783411	8.36E-09	6.61E-05	4.84E-05	respiratory	8.36E-09	4.84E-05	respiratory	100%
291896816611	4.69E-08	2.21E-04	1.74E-04	respiratory	4.66E-08	1.73E-04	respiratory	100%
292017595411	1.23E-08	2.98E-06	1.11E-04	respiratory	1.23E-08	1.11E-04	respiratory	100%
300037851511	4.66E-09	9.93E-08	4.56E-05	respiratory	4.66E-09	4.56E-05	respiratory	100%
300837618511	2.22E-08	8.05E-07	2.26E-04	developmental	2.22E-08	2.26E-04	developmental	100%
300877765611	1.47E-07	5.82E-06	1.50E-03	developmental	1.47E-07	1.50E-03	developmental	100%
300877854911	3.85E-09	4.63E-08	7.83E-05	respiratory	9.86E-08	1.53E-04	respiratory	4%
301115270711	2.94E-08	6.86E-06	1.16E-03	respiratory	2.94E-08	1.16E-03	respiratory	100%
310018399211	3.21E-08	6.50E-06	1.73E-04	respiratory	9.02E-08	6.43E-03	skeletal	36%
310537766111	7.71E-09	2.72E-06	6.03E-05	respiratory	**3.69E-06**	4.74E-02	developmental	0%
310556732411	1.70E-07	2.40E-04	8.35E-04	respiratory	1.70E-07	8.35E-04	respiratory	100%
310798212011	2.96E-09	8.22E-07	4.38E-05	respiratory	2.96E-09	1.80E-02	respiratory	100%
311095281111	1.23E-08	7.86E-06	5.53E-04	skeletal	1.23E-08	5.53E-04	skeletal	100%
311117766511	1.81E-08	2.60E-06	1.99E-04	skeletal	8.18E-08	1.45E-03	respiratory	22%
311317303711	3.04E-08	8.19E-06	2.26E-04	respiratory	3.57E-08	3.97E-04	respiratory	85%
3201112758911	2.48E-09	1.25E-07	2.03E-05	respiratory	2.48E-09	2.03E-05	respiratory	100%
320137302011	2.94E-09	2.01E-07	2.17E-05	respiratory	2.94E-09	2.17E-05	respiratory	100%
330138178911	1.59E-09	5.29E-06	9.79E-06	respiratory	2.37E-09	2.81E-05	neurological	67%
330157287811	5.02E-09	3.17E-06	4.76E-05	skeletal	5.07E-09	4.76E-05	skeletal	99%
330157288011	9.22E-10	1.80E-06	2.47E-05	respiratory	9.22E-10	2.47E-05	respiratory	100%
340095133011	1.01E-08	1.90E-05	2.51E-04	respiratory	2.10E-08	1.70E-03	skeletal	48%
340158093811	9.37E-09	1.06E-04	9.43E-05	respiratory	1.36E-07	7.32E-03	respiratory	7%
340337989011	1.60E-08	6.02E-05	2.05E-04	respiratory	9.76E-07	1.04E-02	respiratory	2%
350315597111	3.98E-08	1.44E-06	3.71E-04	respiratory	3.98E-08	3.71E-04	respiratory	100%
350457197711	8.38E-08	1.49E-05	8.08E-04	respiratory	8.38E-08	8.08E-04	respiratory	100%
350457991911	3.42E-08	2.46E-05	3.12E-04	respiratory	3.42E-08	3.12E-04	respiratory	100%
360637417811	1.28E-08	1.10E-05	4.44E-05	developmental	1.28E-08	4.44E-05	developmental	100%
360718427811	7.72E-08	1.99E-04	2.03E-03	respiratory	7.86E-08	2.04E-03	respiratory	98%
360757980511	1.30E-09	1.28E-06	3.12E-05	respiratory	1.35E-09	3.14E-05	respiratory	96%
360818309011	3.26E-08	1.48E-03	8.51E-04	respiratory	1.77E-07	1.79E-03	respiratory	18%
361098542611	1.06E-07	7.06E-06	3.66E-04	developmental	1.04E-07	3.60E-04	developmental	100%
370218392811	9.34E-08	4.67E-05	5.76E-04	respiratory	1.11E-07	6.19E-04	respiratory	84%
370358370411	3.80E-08	1.41E-04	2.35E-04	respiratory	**5.55E-06**	1.54E-01	neurological	1%
370458300611	2.72E-08	2.23E-05	2.11E-04	respiratory	1.51E-07	7.17E-03	neurological	18%
370658124311	4.20E-09	9.14E-07	4.77E-05	respiratory	9.79E-08	6.72E-04	respiratory	4%
370718137511	5.02E-08	9.00E-05	1.78E-04	respiratory	**2.07E-06**	1.81E-03	liver	2%
370838048111_1	1.31E-10	3.26E-08	3.01E-06	#N/A	1.31E-10	3.31E-06	#N/A	100%
370838048111_2	2.28E-11	4.81E-09	2.68E-07	respiratory	2.28E-11	2.68E-07	respiratory	100%
371457826011	4.15E-08	2.71E-05	1.45E-04	respiratory	4.63E-07	2.79E-03	developmental	9%
371457826111	8.77E-08	2.69E-05	3.03E-04	developmental	1.36E-07	6.79E-04	developmental	65%
371698514011	7.14E-08	1.70E-04	3.62E-04	respiratory	2.81E-07	1.12E-02	neurological	25%
380558011011	1.31E-08	9.95E-07	4.73E-05	neurological	1.31E-08	4.73E-05	neurological	100%

Table 2b – Maximum Predicted HEM-3 Chronic Risks
Allowable Emissions

	Category Chronic Risk [1]			
Facility NEI ID	**Cancer MIR**	**Cancer Incidence**	**Noncancer Max HI**	**Target Organ**
261396336811	6.90E-08	7.60E-05	2.69E-04	respiratory
261398125511	1.21E-07	3.62E-04	9.53E-04	respiratory
261477239111_1	1.85E-07	3.20E-04	2.30E-03	skeletal
261477239111_2	1.73E-07	5.35E-04	2.50E-03	skeletal
261637422511	1.67E-07	1.37E-03	8.54E-04	respiratory
261638229311	1.11E-07	1.05E-03	8.68E-04	skeletal
270317039811	2.26E-07	1.56E-06	1.16E-03	respiratory
270616173211	1.31E-07	3.71E-05	9.59E-04	respiratory
271117072311	3.51E-08	4.82E-06	4.65E-04	skeletal
271416990811	1.93E-07	5.19E-04	1.03E-03	respiratory
271636772111	6.62E-08	2.14E-04	6.29E-04	respiratory
280197053011	1.23E-07	3.35E-05	1.03E-03	developmental
280596251011	1.77E-07	1.67E-04	8.08E-04	respiratory
280737154411	2.80E-08	6.40E-06	1.09E-04	respiratory
290716032111	4.16E-07	2.40E-03	2.12E-03	respiratory
290777496411	3.04E-07	1.78E-04	2.52E-03	developmental
290837529611	2.37E-08	3.42E-06	1.21E-04	respiratory
290957663711	1.13E-07	3.66E-04	1.08E-03	respiratory
290957664111	5.09E-08	1.35E-04	2.60E-04	respiratory
290975321511	6.77E-08	1.61E-05	6.44E-04	respiratory
290995258811	2.30E-07	5.19E-04	1.18E-03	respiratory
291435363811	1.52E-07	6.88E-05	1.22E-03	skeletal
291656795111	1.90E-07	2.43E-04	1.81E-03	respiratory
291756688411	2.44E-07	6.13E-05	1.91E-03	skeletal
291836783411	1.03E-07	8.11E-04	4.00E-04	respiratory
291896816611	8.53E-08	3.98E-04	4.36E-04	respiratory
292017595411	2.18E-07	5.30E-05	1.11E-03	respiratory
300037851511	2.77E-08	5.90E-07	2.63E-04	respiratory
300837618511	3.39E-08	1.23E-06	3.46E-04	developmental
300877765611	1.65E-07	6.54E-06	1.68E-03	developmental
300877854911	8.85E-08	1.07E-06	7.43E-04	developmental
301115270711	7.05E-08	1.65E-05	1.65E-03	respiratory
310018399211	1.45E-07	3.01E-05	1.03E-03	respiratory
310537766111	1.32E-07	4.64E-05	1.33E-03	skeletal
310556732411	5.71E-07	8.17E-04	2.92E-03	respiratory
310798212011	2.99E-08	8.32E-06	2.85E-04	respiratory
311095281111	9.79E-08	6.33E-05	1.21E-03	skeletal
311117766511	1.74E-07	2.50E-05	3.56E-03	skeletal
311317303711	1.56E-07	4.23E-05	9.75E-04	respiratory
3201112758911	1.84E-08	9.28E-07	1.75E-04	respiratory
320137302011	7.60E-09	5.19E-07	5.93E-05	respiratory
330138178911	2.35E-08	7.82E-05	9.16E-05	respiratory
330157287811	4.88E-08	3.07E-05	1.01E-03	skeletal
330157288011	5.70E-09	1.11E-05	1.38E-04	respiratory
340095133011	5.71E-08	1.07E-04	1.45E-03	respiratory
340158093811	3.88E-08	4.39E-04	3.69E-04	respiratory
340337989011	1.35E-07	5.11E-04	1.29E-03	respiratory
350315597111	1.37E-07	4.96E-06	1.30E-03	respiratory
350457197711	3.77E-07	6.69E-05	3.58E-03	respiratory
350457991911	2.60E-07	1.88E-04	2.47E-03	respiratory
360637417811	1.51E-08	1.30E-05	5.90E-05	respiratory
360718427811	3.35E-07	8.61E-04	8.87E-03	respiratory
360757980511	1.37E-09	1.37E-06	3.31E-05	respiratory
360818309011	3.73E-07	1.76E-02	9.77E-03	respiratory
361098542611	3.17E-07	2.12E-05	1.90E-03	skeletal
370218392811	1.07E-06	5.39E-04	4.19E-03	respiratory
370358370411	5.41E-07	2.01E-03	2.11E-03	respiratory
370458300611	3.65E-07	2.79E-04	3.14E-03	respiratory
370658124311	7.93E-08	1.73E-05	7.54E-04	respiratory
370718137511	2.56E-07	4.60E-04	9.99E-04	respiratory
370838048111_1	5.32E-10	1.15E-07	1.54E-05	#N/A
370838048111_2	1.69E-10	3.31E-08	1.61E-06	respiratory
371457826011	3.02E-07	1.95E-04	1.21E-03	skeletal
371457826111	1.97E-07	6.06E-05	7.69E-04	respiratory
371698514011	6.52E-07	1.57E-03	2.54E-03	respiratory
380558011011	1.31E-07	1.01E-05	5.11E-04	respiratory

Table 3 – Maximum Predicted Acute Risks
Actual Emissions

Facility NEI ID	Pollutant	Maximum Hazard Quotient[1]				
		REL	AEGL1	AEGL2	ERPG1	ERPG2
291836783411	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.46E-07
291836783411	Cadmium compounds	0.00E+00	1.37E-07	1.81E-08	0.00E+00	0.00E+00
291836783411	Formaldehyde	2.18E-06	1.09E-07	7.06E-09	1.00E-07	1.00E-08
291836783411	Hydrochloric acid	5.68E-05	4.42E-05	3.61E-06	2.65E-05	3.98E-06
291836783411	Hydrofluoric acid	1.60E-04	4.68E-05	1.92E-06	2.40E-05	2.40E-06
291836783411	Mercury (elemental)	2.43E-04	0.00E+00	8.57E-08	0.00E+00	6.94E-08
291896816611	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.39E-06
291896816611	Cadmium compounds	0.00E+00	5.66E-07	7.45E-08	0.00E+00	0.00E+00
291896816611	Formaldehyde	2.99E-06	1.49E-07	9.67E-09	1.37E-07	1.37E-08
291896816611	Hydrochloric acid	1.52E-04	1.18E-04	9.65E-06	7.08E-05	1.06E-05
291896816611	Hydrofluoric acid	1.51E-03	4.43E-04	1.82E-05	2.27E-04	2.27E-05
291896816611	Mercury (elemental)	2.85E-04	0.00E+00	1.01E-07	0.00E+00	8.15E-08
292017595411	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.23E-07
292017595411	Cadmium compounds	0.00E+00	2.91E-08	3.83E-09	0.00E+00	0.00E+00
292017595411	Formaldehyde	1.54E-06	7.69E-08	4.98E-09	7.05E-08	7.05E-09
292017595411	Hydrochloric acid	5.58E-05	4.34E-05	3.55E-06	2.60E-05	3.91E-06
292017595411	Hydrofluoric acid	1.31E-04	3.84E-05	1.57E-06	1.97E-05	1.97E-06
292017595411	Mercury (elemental)	1.60E-04	0.00E+00	5.63E-08	0.00E+00	4.56E-08
300037851511	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.22E-06
300037851511	Cadmium compounds	0.00E+00	5.56E-07	7.32E-08	0.00E+00	0.00E+00
300037851511	Formaldehyde	2.98E-06	1.49E-07	9.65E-09	1.37E-07	1.37E-08
300037851511	Hydrochloric acid	6.98E-05	5.43E-05	4.44E-06	3.26E-05	4.88E-06
300037851511	Hydrofluoric acid	8.47E-05	2.48E-05	1.02E-06	1.27E-05	1.27E-06
300037851511	Mercury (elemental)	4.27E-04	0.00E+00	1.51E-07	0.00E+00	1.22E-07
300837618511	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.06E-06
300837618511	Cadmium compounds	0.00E+00	1.33E-06	1.75E-07	0.00E+00	0.00E+00
300837618511	Formaldehyde	2.26E-06	1.13E-07	7.30E-09	1.03E-07	1.03E-08
300837618511	Hydrochloric acid	9.94E-06	7.73E-06	6.33E-07	4.64E-06	6.96E-07
300837618511	Hydrofluoric acid	2.68E-05	7.83E-06	3.21E-07	4.02E-06	4.02E-07
300837618511	Mercury (elemental)	5.21E-04	0.00E+00	1.84E-07	0.00E+00	1.49E-07
300877765611	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.61E-06
300877765611	Cadmium compounds	0.00E+00	8.33E-06	1.10E-06	0.00E+00	0.00E+00
300877765611	Formaldehyde	1.03E-05	5.16E-07	3.34E-08	4.73E-07	4.73E-08
300877765611	Hydrochloric acid	4.04E-04	3.14E-04	2.57E-05	1.88E-04	2.83E-05
300877765611	Hydrofluoric acid	1.14E-03	3.33E-04	1.36E-05	1.71E-04	1.71E-05
300877765611	Mercury (elemental)	1.63E-03	0.00E+00	5.75E-07	0.00E+00	4.66E-07
300877854911	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.77E-07
300877854911	Cadmium compounds	0.00E+00	4.63E-08	6.09E-09	0.00E+00	0.00E+00
300877854911	Formaldehyde	4.49E-06	2.24E-07	1.45E-08	2.06E-07	2.06E-08
300877854911	Hydrochloric acid	1.98E-04	1.54E-04	1.26E-05	9.24E-05	1.39E-05
300877854911	Hydrofluoric acid	9.97E-04	2.92E-04	1.20E-05	1.50E-04	1.50E-05
300877854911	Mercury (elemental)	2.73E-04	0.00E+00	9.64E-08	0.00E+00	7.81E-08
301115270711	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.72E-07
301115270711	Cadmium compounds	0.00E+00	6.92E-07	9.11E-08	0.00E+00	0.00E+00
301115270711	Formaldehyde	6.20E-06	3.10E-07	2.01E-08	2.84E-07	2.84E-08
301115270711	Hydrochloric acid	1.24E-03	9.62E-04	7.87E-05	5.77E-04	8.66E-05
301115270711	Hydrofluoric acid	5.49E-04	1.61E-04	6.59E-06	8.24E-05	8.24E-06
301115270711	Mercury (elemental)	1.57E-04	0.00E+00	5.55E-08	0.00E+00	4.50E-08
310018399211	Beryllium compounds	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.33E-06
310018399211	Cadmium compounds	0.00E+00	4.39E-07	5.77E-08	0.00E+00	0.00E+00
310018399211	Formaldehyde	4.35E-06	2.17E-07	1.41E-08	1.99E-07	1.99E-08
310018399211	Hydrochloric acid	1.28E-04	9.92E-05	8.12E-06	5.95E-05	8.93E-06

Table 4a. Multipathway Cancer Screen Values

Facil ID	Urban or Rural	PB-HAP Grp	Tier 1 Screening Value	Tier 2 Screening Values			
				Fisher	Farmer	Rural Gardener	Urban Gardener
291896816611	R	Arsenic	7.E+01	2.E+00	5.E+00	3.E+00	1.E+00
291896816611	R	Cadmium	4.E-01	1.E-01	4.E-03	4.E-03	2.E-03
291896816611	R	Dioxin	6.E+00	1.E+00	2.E-01	2.E-02	9.E-03
291896816611	R	Methyl Mercury (Hg2)	9.E+00	7.E+00	1.E-03	1.E-03	6.E-04
291896816611	R	POM	4.E-06	2.E-06	1.E-08	1.E-08	4.E-09
291896816611	R	Total Cancer (Arsenic+POM+Dioxin)	8.E+01	3.E+00	6.E+00	3.E+00	1.E+00
292017595411	R	Arsenic	1.E+01	3.E-01	2.E+00	1.E+00	5.E-01
292017595411	R	Cadmium	6.E-02	2.E-02	1.E-03	1.E-03	6.E-04
292017595411	R	Dioxin	8.E+00	5.E-01	6.E-01	6.E-02	3.E-02
292017595411	R	Methyl Mercury (Hg2)	1.E+01	2.E+00	3.E-03	3.E-03	1.E-03
292017595411	R	POM	6.E-06	5.E-07	4.E-08	4.E-08	1.E-08
292017595411	R	Total Cancer (Arsenic+POM+Dioxin)	2.E+01	8.E-01	2.E+00	1.E+00	5.E-01
300037851511	R	Arsenic	1.E+00	3.E-03	1.E-01	6.E-02	3.E-02
300037851511	R	Cadmium	5.E-02	1.E-03	5.E-04	5.E-04	2.E-04
300037851511	R	Dioxin	7.E-01	1.E-02	3.E-02	3.E-03	1.E-03
300037851511	R	Methyl Mercury (Hg2)	2.E-01	2.E-02	3.E-05	3.E-05	2.E-05
300037851511	R	POM	6.E-07	2.E-08	1.E-09	1.E-09	5.E-10
300037851511	R	Total Cancer (Arsenic+POM+Dioxin)	2.E+00	2.E-02	1.E-01	6.E-02	3.E-02
300837618511	R	Arsenic	2.E+01	6.E-02	2.E+00	1.E+00	5.E-01
300837618511	R	Cadmium	3.E-01	1.E-02	4.E-03	4.E-03	2.E-03
300837618511	R	Dioxin	1.E+00	3.E-02	7.E-02	8.E-03	4.E-03
300837618511	R	Methyl Mercury (Hg2)	2.E+00	1.E-01	3.E-04	3.E-04	2.E-04
300837618511	R	POM	1.E-06	4.E-08	4.E-09	3.E-09	1.E-09
300837618511	R	Total Cancer (Arsenic+POM+Dioxin)	2.E+01	9.E-02	2.E+00	1.E+00	5.E-01
300877765611	R	Arsenic	1.E+03		6.E+01	3.E+01	2.E+01
300877765611	R	Cadmium	2.E+01		1.E-01	1.E-01	6.E-02
300877765611	R	Dioxin	7.E+01		2.E+00	2.E-01	9.E-02
300877765611	R	Methyl Mercury (Hg2)	3.E+01		3.E-03	3.E-03	1.E-03
300877765611	R	POM	5.E-05		8.E-08	8.E-08	3.E-08
300877765611	R	Total Cancer (Arsenic+POM+Dioxin)	1.E+03		6.E+01	3.E+01	2.E+01
300877854911	R	Arsenic	2.E+00	1.E-04	9.E-02	5.E-02	2.E-02
300877854911	R	Cadmium	8.E-03	6.E-06	6.E-05	6.E-05	2.E-05
300877854911	R	Dioxin	2.E+00	7.E-04	6.E-02	6.E-03	3.E-03
300877854911	R	Methyl Mercury (Hg2)	3.E+00	4.E-03	4.E-04	3.E-04	2.E-04
300877854911	R	POM	2.E-06	8.E-10	3.E-09	3.E-09	1.E-09
300877854911	R	Total Cancer (Arsenic+POM+Dioxin)	4.E+00	8.E-04	2.E-01	6.E-02	3.E-02
301115270711	R	Arsenic	2.E+00	5.E-03	2.E-01	1.E-01	5.E-02
301115270711	R	Cadmium	2.E-01	3.E-03	2.E-03	2.E-03	7.E-04
301115270711	R	Dioxin	4.E+00	6.E-02	2.E-01	2.E-02	7.E-03

APPENDIX D

COMMENTS SUBMITTED IN THE GREENHOUSE GAS RULE

Kathleen Potter • Senior Environmental Professional • Talen Energy
600 Hamilton Street, Suite 600 • Allentown, PA 18101
(610) 601-0305 • Kathleen.Potter@talenenergy.com

COMMENTS OF TALEN ENERGY CORPORATION AND ITS SUBSIDIARIES

ON

EPA'S PROPOSAL ON 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

EPA Docket No. EPA-HQ-OAR-2023-0072

TABLE OF CONTENTS

I. INTRODUCTION

On May 23, 2023, EPA published in the *Federal Register* its proposal on five separate actions under Section 111 of the Clean Air Act ("CAA") to regulate greenhouse gas ("GHG") emissions from fossil fuel-fired electric generating units ("EGUs"), which encompass steam generating units, integrated gasification combined cycle units ("IGCCs"), and stationary combustion turbines ("Proposal").[1] Specifically, EPA is proposing to revise 40 C.F.R. Part 60 as follows: (1) revise the new source performance standards ("NSPS") under Section 111(b) of the CAA for GHG emissions from new fossil fuel-fired stationary combustion turbines (proposed Subpart TTTTa); (2) revise the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification (proposed Subpart TTTTa); (3) establish emission guidelines pursuant to CAA Section 111(d) for GHG emissions from existing fossil fuel-fired steam generating EGUs (proposed Subpart UUUUb); (4) establish emission guidelines pursuant to CAA Section 111(d) for GHG emissions from the largest, most frequently operated gas-fired stationary combustion turbines (proposed Subpart UUUUb); and (5) repeal the Affordable Clean Energy Rule (Subpart UUUUa).

Talen Energy Corporation and its subsidiaries (collectively, "Talen") is a private independent power producer that owns and/or operates generating assets in six states and employs over 2,000 people. Talen owns a total generating capacity in excess of 12,000 MW from wholly owned and partially-owned assets that use nuclear, coal, oil, and natural gas as fuels. Talen has commitments to cease firing coal at all of its wholly owned facilities by 2028, while also developing multiple renewable projects in the vicinity of its generating assets. However, Talen has ownership in units that are projected to operate at relatively high capacity factors—burning coal and natural gas—and could be subject to the Proposal.

Talen is concerned that the Proposal has many legal and technical deficiencies. The Proposal presents serious questions about its impact on grid reliability, which EPA failed to consider, and the sweeping changes that would result if the Proposal is finalized could implicate the major questions doctrine. Among other areas of concern, Talen does not agree with EPA that carbon capture storage/sequestration ("CCS") and low-GHG hydrogen co-firing, as these technologies currently stand, have been adequately demonstrated as BSER for Phase 2 and 3 for various proposed EGU subcategories. Talen strongly requests that EPA withdraw the Proposal and reissue one that is reflective of current proven technologies. Talen further requests that EPA extend the comment period on the Proposal so that the electric generating sector has more time to sufficiently evaluate how grid reliability may be impacted by the Proposal and how any potential reliability issues can be mitigated.

Talen is part-owner and operator of Units 3&4 of the Colstrip Steam Electric Station ("Colstrip") in Rosebud County, Montana. On behalf of itself as an owner and with knowledge gained as the operator of Colstrip, Talen has significant concerns about the Proposal, particularly as it pertains to existing coal-fired steam generating units. The concerns stem from the unique

[1] 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, 88 Fed. Reg. 33,240 (May 23, 2023).

circumstances of Colstrip. Per the Proposal, Colstrip would be forced to either: (1) retire by the end of 2031; (2) retire by the end of 2034 but adopt an annual capacity factor limit by 20 percent from 2030; (3) retire by the end of 2039 and co-fire 40 percent natural gas from 2030; or (4) operate past 2039 and install CCS with 90 percent carbon dioxide ("CO_2") capture by 2030. For it to operate beyond 2034, Colstrip would need to make massive capital investments, including on supporting infrastructure such as pipelines, to co-fire natural gas or to implement CCS. Colstrip currently does not have any ability to implement either technology. The compliance timeframe set forth in the Proposal to co-fire natural gas or to install CCS by 2030 is unachievable not only for Colstrip, but also for other EGUs across the country, given the unresolved challenges associated with CCS and the lack of availability of nearby natural gas. The financial and technological hurdles to implement the technologies, coupled with the Agency's rulemaking agenda targeting older sources like Colstrip, would likely render the investments economically unviable. Prematurely shutting down Colstrip, however, would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission—factors that were not considered by EPA in issuing the Proposal.

To that end, Talen requests that, if EPA finalizes the Proposal, the Agency provide more compliance lead time by extending the retirement date for existing coal-fired steam generating units. In particular, Talen requests that EPA extend the retirement date for the Imminent-term subcategory option to December 31, 2035, such that units in this subcategory would be allowed to continue routine methods of operations and maintenance—without adopting an annual capacity factor limitation—until ceasing operations.

The Near-term subcategory option of only operating with a 20 percent capacity factor is also likely infeasible, and the compliance date by which units in this subcategory must operate with such limitation is too early. Colstrip is a baseload plant because of its need to meet the demand. The three additional years (from January 2032 to end of 2034) of operational life that the Proposal would allow without additional capital investments is a critical timeframe, but the reduction in capacity factor is unworkable for a baseload plant like Colstrip. Large coal-fired steam generating units are not designed to operate as peakers (< 20 percent capacity factor) and certainly not economically viable in that mode. Therefore, Colstrip would likely not elect the Near-term subcategory, and Colstrip would likely be forced to shut down at the end of 2031. This does not leave sufficient time to permit and install replacement power in the region and would likely jeopardize grid reliability and transmission. This further supports the extension of the Imminent-term subcategory retirement date to the end of 2035.

Besides Colstrip, Talen owns combined cycle stationary combustion turbine units, such as the Lower Mount Bethel Power Plant ("LMBE") in Bangor, Pennsylvania. LMBE is a natural gas-fired facility consisting of two combustion turbines and one steam turbine, which produces approximately 600 MW of electricity, can be considered a baseload plant, and has been operating since 2004.

Talen supports EPA's methodology for calculating electric generating capacity—as implemented in the Regulatory Impact Analysis ("RIA")—to determine whether an existing fossil fuel-fired stationary combustion turbine would be subject to the proposed GHG emission guidelines. That methodology appears to use the net generating capacity value of the combustion turbines and to divide that capacity by the number of combustion and steam turbines in calculating electric generating capacity. Talen's support of this methodology is appropriate because it results in an electric generating capacity that more closely reflects the capacity of each combustion turbine individually, as the combustion turbines—not the steam turbine—are the primary sources of CO_2. Based on the methodology applied in the RIA, the LMBE combustion turbines would not be subject to the Proposal.

However, the methodology implemented by EPA in the RIA differs from the guidelines for calculating capacity that is articulated in the FAQs Memo. Talen therefore asks EPA to amend the FAQs Memo, such that it is consistent with the approach applied by the Agency in the RIA, or to simply utilize the electric generating capacity of the individual combustion turbines. Should EPA instead finalize the methodology articulated in the FAQs Memo, Talen requests EPA to reissue the Proposal for existing large, frequently operated fossil fuel-fired stationary combustion turbines. The final rule would otherwise be arbitrary and capricious because the analysis underlying the Proposal would be deeply flawed, as the Proposal would significantly underestimate the cost and impact to the electric generating sector and currently contains a number of ambiguities, including EPA's rationale for the 300 MW threshold of large stationary combustion turbines.

In addition, Talen owns a number of units that currently fire oil or gas or that are undergoing conversions to fire solely oil or gas within the next five years. While Talen supports EPA's position to not impose additional controls on existing gas-fired and oil-fired steam generating units—including not establishing BSER requirements for Low-load units and establishing routine methods of operation and maintenance for Intermediate-load and Base-load units, Talen requests that EPA eliminate presumptively approvable standards of performance and reconsider setting emission limits of zero percent increase over a prescribed baseline emission rate. However, should EPA choose not to eliminate such emission limitations, Talen requests that EPA adopt the higher end of the range of presumptively approvable standards of performance offered by the Agency.

Furthermore, the degree of emission limitation (zero percent) set forth in the Proposal is too restrictive, given that there are no controls of CO_2 to dial up or down on any EGU. The CO_2 emission rate is largely only affected by the load range in which the unit is operating, which in turn depends on how the unit is being dispatched by a regional transmission operator ("RTO"), such that there is no control over the CO_2 emission rate. EPA should thus not impose additional requirements or emission restrictions beyond routine methods of operation and maintenance for existing oil- and gas-fired steam generating units. However, should EPA choose not to eliminate the degree of emission limitation, Talen believes that EPA should provide greater flexibility such that the degree of emission limitation accounts for factors outside of the owner/operator's control, including changes in future dispatch, would still be consistent with EPA's proposed BSER—routine methods of operation and maintenance.

Lastly, EPA should not establish BSER for any additional classes of existing stationary combustion turbines, such as small and less frequently used units. Imposing additional requirements would not be economical, would likely trigger premature retirement of such units, and would likely disrupt reliability. These smaller units, which tend to operate as peakers, will be critical to the grid as more intermittent renewables are added, ensuring that grid reliability is maintained when renewable generation is impacted by weather conditions and time of day.

Talen is a member of the Class of ’85 Regulatory Response Group. Talen supports and incorporates the comments submitted by the Class of 85’ Regulatory Response Group.

II. OPPORTUNITY FOR PUBLIC COMMENT

EPA must extend the comment period to satisfy the Administrative Procedure Act (“APA”) requirements. Although EPA granted a 15-day extension of the original comment deadline,[2] it is not adequate to allow companies with potentially affected EGUs to fully analyze the impacts of the Proposal and submit comprehensive comments to EPA.[3] The APA’s notice and comment requirements are intended to (1) ensure that agency regulations are tested via exposure to diverse public comment, (2) ensure fairness to affected parties, and (3) give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review.”[4] When a significant number of commenters have requested an extension, that further supports later findings that a rule is deficient under the APA because it deprived the public of the opportunity to provide informed comments.[5]

In this instance, EPA should extend the comment period by another 60 days given the profound impacts the Proposal has on the electric generating industry. More time is needed for companies, states, RTOs, regional reliability authorities, and independent system operators (“ISOs”) to adequately evaluate the cost and feasibility of the Proposal.

The Proposal alone, without the proposed regulatory text, is 181 pages long in the *Federal Register*, along with 67 supporting documents (as of August 7, 2023) available in the docket that are highly technical in nature. Approximately three weeks after publishing the Proposal in the *Federal Register* EPA issued a memorandum on its website,[6] “Applicability of Emission Guidelines to Existing Stationary Combustion Turbines FAQs” (June 12, 2023) (“FAQs Memo”), containing new information that significantly deviates from the proposed regulatory text available in the docket and the published preamble. The FAQs Memo was not even added to the rulemaking docket until July 7, 2023.[7] Further, on the same day, EPA posted another memorandum to the

---

[2] 88 Fed. Reg. 39,390 (June 16, 2023).

[3] *See, e.g., California v. U.S. Dep’t of the Interior*, 381 F. Supp.3d 1153, 1172 (N.D. Cal. 2019).

[4] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 449 (3d Cir. 2011).

[5] *See, e.g., id.*; *California v. U.S. Dep't of the Interior*, 381 F. Supp. 3d at 1153. Another indication that the public has been deprived of the opportunity to provide informed comments is the fact that EPA initially declined to proceed with a full panel review in determining whether the Proposal would have a significant impact on small businesses. During the Small Business Review *Pre*-Panel discussion to determine the proposed rule’s significant impact, EPA only asked the panel members about reporting burdens—a significantly minor concern compared to the range of issues covered in this Proposal. While Talen appreciates that EPA recently switched course and decided to move forward with a full panel review, this further warrants extending the comment period by more than 15 days so that members of the review panel have sufficient time to provide additional feedback.

[6] https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

[7] Dkt. ID No. EPA-HQ-OAR-2023-0072-0143.

rulemaking docket, the Additional Modeling Memo, along with 22 attachments and four new Integrated Planning Model ("IPM") model run outputs, to supplement the record.[8]

The Proposal is complicated and encompasses two proposed new substantive rules: (1) Subpart TTTTa to address NSPS for stationary combustion turbines and significant modifications to steam electric generating units; and (2) Subpart UUUUb to address emission guidelines for existing EGUs. EPA is seeking comment on several aspects of both proposed rules. Yet, by providing inadequate time to analyze the aspects, it appears that the Agency is rushing through the comment period in lieu of seeking thoughtful responses to its requests for comments. When rules are considered "significant regulatory action" the time allotted for comments should reflect this.[9] There is no consent decree, statutory deadline, or other similar driver to justify the compressed schedule for affected entities to review the Proposal and provide comments.

The Proposal also is one of several key rulemakings affecting Talen that EPA is simultaneously undertaking. Given the back-to-back comment deadlines, it is difficult to respond meaningfully to each of these rulemakings and fully evaluate the potential impacts on electric generating unit operations. The other Agency proposals affecting the electric generating industry that have overlapped on review and preparation of comments Talen include: (1) the proposed rule amending the National Emissions Standards for Hazardous Air Pollutants for the Coal- and Oil-fired Electric Utility Steam EGUs (commonly referred to as "MATS," "2023 MATS Rule"), 88 Fed. Reg. 24,854 (Apr. 24, 2023) (comments submitted June 23, 2023, Dkt. ID. No. EPA-HQ-OAR-2018-0794-5987); and (2) the proposed rule on the Hazardous Solid Waste Management System: Disposal of Coal Combustion Residuals ("CCR") from Electric Utilities; Legacy CCR Surface Impoundments ("2023 CCR Rule"), 88 Fed. Reg. 31,982 (May 18, 2023) (comments submitted on July 17, 2023, Dkt. ID. No. EPA-HQ-OLEM-2020-0107-0237).

These rulemakings, both individually and collectively, have wide-ranging implications for EGUs across the country, such as Colstrip, and they each have hundreds of supporting documents that are highly technical in nature. Talen strongly recommends that EPA harmonize the recent suite of rulemakings aimed at EGUs. Talen needs to be able to holistically analyze these proposed rulemakings and others that EPA may be contemplating, such as whether to regulate other existing stationary combustion turbines—particularly as to how all of these rules' requirements impact existing EGUs' short- and long-term operating plans, how electric generating companies should structure replacement generation, and how the rules may impact the reliability and affordability of electricity.

Given the complexity and timing of EPA's proposals and the short turn-around time for comments, more time is required to provide accurate and meaningful feedback to EPA on the Proposal, as well as respond to the specific questions posed by the Agency. Talen needs to undertake thorough analyses as to what options are available and feasible to achieve compliance with the proposed standards, requiring significant staff support as well as the retention of

[8] *See* EPA, *Integrated Proposal Modeling and Updated Baseline Analysis* ("Additional Modeling Memo") (Jul. 7, 2023), (later issued Dkt. ID No. EPA-HQ-OAR-2023-0072-0237). https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

[9] *Centro Legal de la Raza v. Exec. Office for Immigration Rev.*, 524 F. Supp. 3d 919, 955 (N.D. Cal. 2021).

consultants to conduct such analyses. Further, another Colstrip owner needs to engage with its respective public utility commission to determine what course of action would have the least impact on grid reliability and electricity costs to customers, including whether to install controls, which could require extended outages for installation, or whether to seek early retirement and the development or purchase of replacement generation.

III. CCS AND LOW-GHG HYDROGEN CO-FIRING DO NOT QUALIFY AS BSER

In the Proposal, EPA identifies CCS and co-firing of low-GHG hydrogen as BSER for various EGU subcategories.[10] EPA has proposed CCS and low-GHG hydrogen co-firing because: (1) "a range of cost-effective technologies and approaches to reduce GHG emissions from [fossil fuel-fired EGUs] are available to the power sector"; (2) "multiple projects are in various stages of operation and development—including carbon capture and sequestration/storage (CCS) and co-firing with lower-GHG fuels"; and (3) "Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector."[11] However, these technologies—which for CCS encompasses carbon capture, compression, transportation pipeline networks, and large-scale permanent sequestration; and which for low-GHG hydrogen co-firing encompasses scalability, transportation pipeline networks, and storage systems—have not been adequately demonstrated.

To start, the fact that Congress has provided incentives to develop the technologies should have no bearing on EPA's cost-effectiveness evaluation, as there is no guarantee that the incentives will continue to be available, let alone result in the technologies being commercially available by the timeframe EPA proposes, or that a source will meet the eligibility requirements imposed by the applicable federal agency. In fact, Congressional incentive funding demonstrates the contrary. Historically, Congressional allocations do not match actual funding. For example, in the Energy Policy Act of 2005, Congress allocated $3.275 billion for the development of hydrogen fueling infrastructure.[12] However, only $1.48 billion in actual funding materialized from 2006 to 2010; and while funding continued through 2019, no vast infrastructure was developed in the nearly two-decades long funding timeframe.[13] Accordingly, the $9.5 billion allocated for the four regional clean hydrogen hubs pursuant to the Inflation Reduction Act ("IRA") likely will be significantly less in actual funding. In addition, the IRA funding is limited to a 10-year period and the credits are available only until the four-year phase-out is triggered in the later of 2032 or the year that emissions from the power sector are 25 percent of 2022 levels. CCS and hydrogen co-firing projects likely would not be cost-effective once the credits cease.

Moreover, the fact that Congress provided incentives in the IRA to develop CCS and hydrogen co-firing is itself evidence of the still-nascent state of the technologies' commercial availability and the related infrastructure's deployment (such as production, transportation, and

---

[10] *See, e.g.*, 88 Fed. Reg. at 33,243.

[11] *See id.* at 33,242-43.

[12] *See* Pub. L. No. 109-58, tit. VIII, 119 Stat. 594, 844-55 (2005).

[13] *See* U.S. Dep't of Energy, *Budget* (last visited Aug. 1, 2023), https://www.hydrogen.energy.gov/budget.html; *see also* Alan C. Lloyd & Robert S. Walker, Hydrogen and Fuel Cell Technical Advisory Committee, *Hydrogen and Fuel Cell Technical Advisory Committee Biennial Report to the Secretary of Energy* 3 (2007) ("Funding for the hydrogen program should be increased at least to the $3.275 Billion authorized by [the Energy Policy Act of 2005.]").

storage). Thus, the IRA's incentives do not to support a determination that either of the technologies has been "adequately demonstrated." While these technologies demonstrate potential and the power sector is working toward their deployment, they simply are not adequately demonstrated at this time nor is it likely they will be by the proposed compliance deadlines.

The information on which EPA has relied for identifying CCS and low-GHG hydrogen co-firing as BSER primarily rests on demonstration projects, vendors' forecasts for availability of certain technologies which are not guaranteed, and the assumption that such technologies will be "adequately demonstrated" by the compliance deadlines set forth in the Proposal. For example, although the Proposal states that "some turbines are available now that can combust 100 percent hydrogen in the future and there is significant evidence that such turbines will be more widely available by the 2030s," the only support for this statement is a 2022 article, "Siemens Energy Explores Gas Turbines' Future in Net-Zero Energy Mix," and is limited to an unofficial statement made by a member of Siemens Energy's executive board.[14] The other articles on which EPA relies to support low-GHG hydrogen co-firing as BSER are similarly unconfirmed—one describes how a vendor "aims to achieve 100% hydrogen,"[15] and another notes that a vendor "has set an *ambitious target* to have all its new gas turbines capable of burning 100% hydrogen on or before the end of 2030."[16] EPA's citations show that it relied on the "ambitious target[s]" and "aims" of vendors published in aspirational marketing and public relations materials. These are not sufficient indications of a system of emission reduction that is "adequately demonstrated" for the purposes of establishing BSER.

EPA would exceed its statutory authority by establishing technology-based standards of performance that do not meet the statutory requirement in CAA Section 111(a)(1) of being "adequately demonstrated."[17] EPA should not determine that a control has been "adequately demonstrated" where the control is new and not yet in widespread commercial use. Further, EPA should not speculate as to the timeframe for the development of a control and then establish requirements that take effect at that future time.[18] Citing *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973), EPA acknowledges that, while BSER need not mean actual routine use, any projection based on existing technology must be "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."[19] In fact, *Portland Cement* further states that the validity of EPA's projection rests on the reliability of the prediction and the nature

[14] 88 Fed. Reg. at 33,308; *see also* Roberta Prandi, *Siemens Energy Explores Gas Turbines' Future in Net-Zero Energy Mix*, Diesel & Gas Turbine Worldwide (Nov. 18, 2022) (including significant discussion on the use of biodiesel, cracked ammonia, methanol, hydrogenated vegetable oils and Fatty Acid Methyl Esters for co-firing, which EPA eschews in its Proposal), https://www.dieselgasturbine.com/news/siemens-energy-explores-gas-turbines-future-in-net-zero-energy-mix/8024799.article.

[15] 88 Fed. Reg. at 33,308 n. 407 (citing Kevin Lark, *Mitsubishi Highlights Four Hydrogen Projects at CERAWeek*, Power Engineering (Mar. 8, 2022), https://www.power-eng.com/hydrogen/mitsubishi-power-highlights-four-hydrogen-projects).

[16] *See id.* at 33,308 n. 409 (citing Siemens Energy, *Siemens Energy to Provide Hydrogen-Capable Turbines to Back Up Utility-Scale Solar Installation in Nebraska* (June 17, 2021), https://press.siemens-energy.com/global/en/pressrelease/siemens-energy-provide-hydrogen-capable-turbines-back-utility-scale-solar-installation.

[17] 42 U.S.C. § 7411(a)(1); *see also* 42 U.S.C. § 7411(d).

[18] *See* 88 Fed. Reg. at 33,244.

[19] *See id.* at 33,272.

of the assumption, and that "the question of availability is partially dependent on 'lead time', the time in which the technology will have to be available."[20]

Notwithstanding the language in CAA Section 111(a)(1), EPA is projecting when CCS and low-GHG hydrogen co-firing and the related actions/infrastructure to support those technologies will be widely available for installation, with little record to support such projections—and even less legal authority to justify such a scant record. EPA's unsupported assumptions include when production of low-GHG hydrogen will be at scale for safe use in stationary combustion turbines, when networks of pipelines needed to support the technologies will have safety concerns satisfied and will be permitted and constructed, and when permitting for geologic fields for CO_2 sequestration will be in place and safety is no longer a concern, among several other assumptions. All of these assumptions are further complicated by the fact that EPA fails to present any "big picture" of how CCS and low-GHG hydrogen connect/interact with electric generators' existing (and future) transmission distribution systems. And, to the extent there are no studies on these technologies' interaction with the grid, considerable time is needed to identify if such integration would be feasible in the first place. Predicting the confluence of all of these activities includes a combination of projections, assumptions, and optimism, which would be far too speculative to satisfy a reasonable projection under *Portland Cement*. In fact, the court in *Portland Cement* remanded the Agency's projections because it could "not identify the location[, details,] or methodology used in the one successful test."[21] In the Proposal, EPA is making *multiple* projections that lack a coherent methodology or details to support its projections.

Further, the issue in *Portland Cement* was not whether the technology actually existed and was available to facilities, which it was, but rather whether that technology, if implemented, would be able to achieve the standards and whether EPA's cost analysis was accurate.[22] The concerns that underlie the Proposal are more fundamental because here, unlike in *Portland Cement*, EPA has not even shown that the technology is available in the first place.

The Proposal is distinguishable from prior rulemakings where EPA "provided the regulated sector with lead time to accommodate the availability of technology."[23] Lead times for prior rulemakings were based on the time needed to install demonstrated controls (for example, for manufacturers to ramp up production and competition for the services of a finite number of vendors), not "crystal ball" projections of when non-demonstrated controls and required infrastructure would appear.[24] Additionally, those lead times were significantly shorter (*e.g.*, two years) than for CCS and low-GHG hydrogen co-firing. The Agency cites to the implementation of flue gas desulfurization ("FGD") to address SO_2 emissions subsequent to the 1971 NSPS for electric generating units for the proposition that "companies with the expertise to install complex emission control equipment can rapidly ramp up capacity in response to a regulatory driver."[25]

---

[20] *Portland Cement*, 486 F.2d at 391-92.

[21] *Id.* at 392.

[22] *See id.* at 387.

[23] 88 Fed. Reg. at 33,289.

[24] *See, e.g.*, 81 Fed. Reg. 59,221 (Aug. 29, 2016) (Municipal Solid Waste Landfills); 78 Fed. Reg. 58,415 (Sep. 23, 2013) (Storage Vessels (Crude Oil and Natural Gas Production, Transmission and Distribution)); 77 Fed. Reg. 49,489 (Aug. 16, 2012) (Petroleum Refineries).

[25] 88 Fed. Reg. at 33,367.

However, what EPA fails to consider is that FGD was already demonstrated at several EGUs, specifically among EGUs that had implemented or contracted for SO_2 removal systems at the time of the rule.[26] Further, FGD does not require complex and significant support infrastructure, such as pipelines and access to geologic fields and associated permitting and land acquisition issues, which makes CCS and low-GHG hydrogen co-firing incomparable to installation of FGD technology.

In addition, CCS and low-GHG hydrogen co-firing require significant retrofit modifications that may not be possible at some existing units. EPA also fails to consider the effects of state and local codes and standards, which may cause delays and additional roadblocks for implementation of CCS and low-GHG hydrogen co-firing, particularly with respect to the attendant infrastructure required. Hydrogen specifically comes with inherent safety risks during transportation, storage, and combustion, which would be regulated by other federal requirements, as well as state and local fire codes and standards.[27] It is probable that states and localities will resist operation of hydrogen pipelines in their areas due to safety concerns, as demonstrated by the recent opposition to two pipelines in the mid-Atlantic region. And, EPA has failed to address how its proposed BSER of low-GHG hydrogen co-firing and CCS with their attendant infrastructure needs fit within the Supreme Court's decision regarding the limits of EPA's CAA authority in *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). Moreover, the Proposal presents serious questions about its impact on grid reliability, which EPA failed to consider, and the sweeping changes that would result if the Proposal is finalized could implicate the major questions doctrine.[28]

EPA cannot rely on a multi-phase BSER to circumvent the statutory requirement that BSER be "adequately demonstrated." Forcing the implementation and regulation of undemonstrated technology that is still in the developmental stage on the electric generating industry is not necessary as the CAA specifically requires EPA, for the NSPS, to "*at least* every 8 years, review and, if appropriate, revise" the standards.[29] Thus, rather than trying to predict the future by establishing standards based on inadequately demonstrated GHG emission reduction technologies for which EPA has to predict future availability, the Agency should reevaluate the technologies that are in fact "adequately demonstrated" to establish as BSER, and modify the

---

[26] Sixteen EGUs implemented or were implementing limestone scrubbing; one had implemented or was implementing sodium hydroxide scrubbing installations; two had implemented or were implementing magnesium oxide scrubbing installations; and one had implemented or was implementing catalytic oxidation. 37 Fed. Reg. 5,768 (Mar. 23, 1972).

[27] *See e.g.*, 88 Fed. Reg. at 33,308 n. 410 (citing L.A. Dep't of Water & Power, *Scattergood Modernization Project: Responses to Questions from Energy & Environmental Committee*, at 10 (Feb. 3, 2023), https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf). *See generally* National Fire Protection Association, Model Hydrogen Technologies Code (2023), https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=2 (discussing safeguards on the generation, installation, storage, piping, use, and handling of hydrogen in compressed gas form or cryogenic liquid form).

[28] *See* Charles Owen, *Manchin says FERC agrees to assess impact of EPA plan on natural gas, coal plants*, Bluefield Daily Telegraph, Aug. 8, 2023, https://www.bdtonline.com/news/manchin-says-ferc-agrees-to-assess-impact-of-epa-plan-on-natural-gas-coal-plants/article_da4a6952-353b-11ee-b0a5-c7e17bc4663a.html (Senator Joe Manchin announcing that the Federal Energy Regulatory Commission ("FERC") will hold a reliability technical conference to evaluate impacts to the nation's electrical grid from the latest power plant rules proposed by EPA).

[29] 42 U.S.C. § 7411(b)(1)(B) (emphasis added).

proposed standards to reflect this so that they can be implemented on a broad industry-wide basis regardless of company-specific circumstances or location.

Lastly, EPA's proposed regulations need to clarify that these are emissions standards and not technology mandates. Based on the proposed regulatory text, sources must meet the standards based on the subcategory into which they are slotted. Installation of BSER is not directly addressed in the proposed regulatory text for each applicable standard although, for the Section 111(d) standards, the increments of progress that EPA proposes identify milestones associated with the installation of the technologies determined to be BSER. EPA must make it explicitly clear for both Subparts TTTTa and UUUUb that sources are <u>not</u> required to install and operate the technology that EPA determined is BSER if they can otherwise meet the standard and that, for Subpart UUUUb, states have the authority to tailor the increments of progress according to how compliance with the standard will be achieved. It is important for EPA to address this directly because the technologies on which standards are based may not be the ones deployed based on company-specific circumstances.

IV. EPA MUST PROVIDE SUFFICIENT COMPLIANCE LEAD TIME AND RECONSIDER BSER FOR EXISTING COAL-FIRED STEAM GENERATING UNITS

The Proposal subcategorizes existing coal-fired steam generating units primarily by the unit's operating horizon, as well as by load level. These subcategories include: (1) "Imminent-term" (cease operating before January 1, 2032); (2) "Near-term" (cease operating by December 31, 2034, and adopting an annual capacity factor limit of 20 percent); (3) "Medium-term" (operate after December 31, 2031, but cease operating before January 1, 2040, *and* do not meet the definition of "Near-term"); and (4) "Long-term" (no commitment to cease operating before January 1, 2040).[30] For the Imminent- and Near-term subcategories, EPA is proposing to determine that BSER is routine methods of operation and maintenance, and the presumptively approvable standard is an emission rate limit in lb CO_2/MWh-gross not to exceed the unit-specific baseline.[31] For the Near-term subcategory, EPA is proposing to require units to adopt a capacity factor limit of 20 percent beginning January 1, 2030.[32] For the Medium-term subcategory, EPA is proposing BSER to be 40 percent natural gas co-firing on a heat input basis. The presumptively approvable standard is a 16 percent reduction in the unit's annual baseline emission rate on a lb CO_2 per MWh-gross basis. Compliance would be required by January 1, 2030.[33] For the Long-term subcategory, EPA is proposing CCS with 90 percent CO_2 capture as BSER. The presumptively approvable standard is an 88.4 percent reduction in the unit's annual baseline emission rate on a lb CO_2 per MWh-gross basis. Compliance would be required by January 1, 2030.[34]

Colstrip is one of the largest coal-fired electric generating facilities west of the Mississippi River, supplying electricity throughout Montana and the Pacific Northwest. Talen has a 15 percent

---

[30] *See* 88 Fed. Reg. at 33,344.

[31] *See id.* at 33,359.

[32] *See id.*

[33] *See id.*

[34] *See id.*

ownership stake in Colstrip, which currently consists of two active coal-fired generating units capable of producing up to 1,480 MW of electricity that have been operating for approximately 37 years. Each of the units has approximately 740 MW of generating capacity, and the adjacent Rosebud coal mine supplies Colstrip's low-sulfur subbituminous coal.

Despite the importance of Colstrip to Montana and the surrounding region, Colstrip's future is uncertain. Colstrip's remaining life and future generation may be limited by the IRA, which EPA's IPM runs suggest will cause Colstrip to significantly reduce generation by 2030 as more renewables come online and other EPA rulemakings targeting older sources such as Colstrip are implemented, such that Colstrip would not operate beyond 2035. These rulemakings, excluding the Proposal and forthcoming ones, impacting Colstrip include the 2023 CCR Rule and 2023 MATS Rule.

The costs associated with implementing 40 percent natural gas co-firing or installing CCS to achieve 90 percent CO_2 so that Colstrip can operate beyond 2034 are massive. Colstrip would need to spend significant time, resources, and investments to not only implement the technologies but also to construct supporting infrastructure. When added to the costs associated with complying with the proposed requirements in other rulemakings that impact Colstrip, such as the 2023 MATS Rule, the investments required for Colstrip to operate beyond 2034 would cost many hundreds of millions of dollars. Such costs would likely render Colstrip financially unviable, given Colstrip's uncertain but limited future.

Colstrip's owners need significantly more time to make and implement pivotal decisions concerning Colstrip's future operations. Any closure plans would necessitate intensive engagement and coordination among stakeholders because Colstrip is vital to Montana and the surrounding region. As concluded in a 2017 study by University of Montana's Bureau of Business and Economic Research, "[t]he early retirement of Colstrip Units 3 and 4 would ultimately produce:

- [A]n economy with, on average, almost 3,300 fewer jobs than would have been present if the units continued to operate through the 2028-43 period[.]

- [A] loss of income received by Montana households varying between $250 and $350 million per year, adding up to a total of about $5.2 billion over the full 16-year period 2028-43. Losses in after-tax income . . . for Montana households would total almost $4.6 billion over the same period.

- [D]eclines in annual gross sales by businesses and other organization, or economic output, between $700 and $800 million, cumulating to $12.5 billion over the full sixteen period.

- [A] decline in population which occurs as workers and families migrate to other economic opportunities, growing to more than 7,000 people by year 2043."[35]

[35] Patrick M Barkey. *The Economic Impact of the Early Retirement of Colstrip Units 3 and 4 Final Report*, at 6 (June 2018).

Colstrip is vital to ensuring that Montanans have affordable and reliable electricity, especially during peak winter and summer months. Colstrip is one of Montana's most important energy assets, especially as demand for reliable baseload power in the western U.S. continues to grow. As Montana state Governor Gianforte has recognized, Montana needs Colstrip.[36]

Thus, EPA's proposal on existing coal-fired steam generating units, has far-reaching ramifications given Colstrip's unique circumstances. Talen strongly recommends that EPA reconsider the Proposal to provide the relief requested by Talen herein.

A. Talen Requests that EPA Revise the Proposed Subcategories by Extending the Retirement Date, Especially for the Imminent-Term Subcategory

Per the Proposal, Colstrip would be forced to either: (1) retire by the end of 2031; (2) retire by the end of 2034 but adopt an annual capacity factor limit by 20 percent from 2030; (3) retire by the end of 2039 and co-fire 40 percent natural gas from 2030; or (4) operate past 2039 and install CCS with 90 percent CO_2 capture by 2030. For it to operate beyond 2034, Colstrip would need to make massive investments, including on supporting infrastructure such as pipelines, to co-fire natural gas or to implement CCS. Colstrip currently does not have any ability to implement either technology. The compliance timeframe set forth in the Proposal to co-fire natural gas or to install CCS by 2030 is unachievable not only for Colstrip but also for EGUs across the country, given the unresolved challenges associated with both technologies (as discussed in Section IV.C and IV.D). The financial and technological hurdles to implement the technologies, coupled with the Agency's rulemaking agenda targeting older sources like Colstrip, would likely render the investments economically unviable. Prematurely shutting down Colstrip, however, would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission—factors that were not considered by EPA in issuing the Proposal.

Moreover, EPA's IPM model assumes that Colstrip will fall in the Near-term subcategory by electing to cease operations by the end of 2034 and to adopt a 20 percent annual capacity limit.[37] EPA is wrong to assume that Colstrip will elect to cease operations by the end of 2034, as peaking operation is detrimental to a coal-fired steam generating unit and uneconomic. Operating coal-fired steam generating units as peakers is detrimental because such units are comprised of large pieces of equipment (*e.g.*, coal mills, boiler feed pumps, hydraulic and cooling systems) designed to start and run at steady state. Starting and stopping such equipment frequently leads to damage and malfunctions, ultimately impacting the ability of the units to operate reliably and economically. For instance, steam generating units have very large surface areas of metal tubes to transfer heat from the coal combustion to the boiler water. Every start and stop causes the metal tubes to expand and contract, and, over time, increases the likelihood of leaks and outages and reduces the units' life. All of these issues result in higher costs with less revenue per year, which ultimately make operating coal-fired units as peakers uneconomic.

[36] State of Montana Newsroom, *Governor Gianforte: 'Montana Needs Colstrip*, Jan. 17, 2023, https://news.mt.gov/Governors-Office/Governor_Gianforte_Montana_Needs_Colstrip.

[37] EPA, *Analysis of the Proposed Greenhouse Gas Standards and Guidelines – Power Sector Modeling*, https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines.

For these reasons, it is unlikely that Colstrip could operate as a peaker, and therefore, Colstrip would likely be forced to retire at the end of 2031 under the "Imminent-term" subcategory. EPA fails to account for the possible consequences of Colstrip adopting a 20 percent capacity factor limitation from 2030-2034—not to mention the strong likelihood of retirement in 2031—including how the lack of generation would impact grid reliability and costs. If the Proposal is finalized, Subpart UUUUb would result in large numbers of EGUs retiring or implementing modifications on a compressed and concurrent timeframe, which likely would affect grid reliability during that timeframe.

EPA's IPM Model shows a nearly 30 percent (approximately 8,100 GWh) decrease in total generation from 2028 to 2030 for Montana. While EPA's IPM model also shows a 4.7 percent (approximately 32,272 GWh) increase in generation during that time frame in the WECC region, the model fails to show that electricity cannot be imported from other parts of the WECC region to the state. Montana's transmission system and its connections to utilities in other states are currently not designed to import significant additional amounts of electricity, and there is very little Available Transmission Capacity that could be used to import additional electricity to Montana's system. Coupled with the fact that there presently is not any proposed interstate transmission lines or upgrades that would facilitate added import capability into Montana, EPA's IPM Model demonstrates that the Proposal will potentially cause a significant reliability issue due to: (1) the decrease in electric generation in Montana, if units like Colstrip are forced to adopt a 20 percent annual capacity factor limit by 2030 and shut down before 2034; (2) the increase in the demand resulting from the shift to electrification; and (3) the limited ability to bring in electricity from other states given Montana's current transmission infrastructure. The gap between supply and demand is also likely to increase the price of electricity for Montanans.

In light of EPA's recent rulemakings, such as this Proposal, regional grid operators have been actively evaluating the changes in generation resources expected by 2030 and beyond. For instance, the February 2023 Energy Transition Report produced by the Pennsylvania-New Jersey-Maryland Interconnection ("PJM")—where Talen has four fossil fuel-fired plants in PJM's territories—identifies several trends which present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation, including the risk that retirements may outpace the construction of new resources.[38] According to the report, 40 GW of existing generation are at risk of retirement by 2030, which represents 21 percent of PJM's current installed capacity.[39] PJM's long-term load forecast, however, only shows a demand growth of 1.4 percent per year for the PJM territory over the next 10 years.[40] The projections in the report indicate that the current pace of new generating capacity would be insufficient to keep up with expected retirements and demand growth by 2030, particularly when coupled with the projections that reserve margins in the system will decrease significantly from 22 percent to 25 percent in 2023 and from 3 percent to 15 percent in 2030.[41] The concerns identified by PJM in its territories are not unique, and such concerns are more

[38] *See* PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, (Feb. 24, 2023) https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[39] *See id.*

[40] *See id.*

[41] *See id.*

significant in states like Montana, where there is limited ability to import electricity to address reliability risks.

It is thus critical for grid reliability that the earliest retirement date for the proposed subcategories is delayed to 2035 or later. Talen strongly requests that EPA provide more compliance lead time by extending the retirement date for the existing coal-fired steam generating unit subcategories. In particular, Talen requests that the Agency extend the retirement date for the Imminent-term existing coal-fired steam generating unit subcategory to December 31, 2035, where units in this subcategory would be allowed to continue routine methods of operations and maintenance—without adopting an annual capacity factor limitation—until ceasing operations.

B. Talen Recommends that EPA Make Further Revisions on its Proposed Subcategories

Aside from pushing back the retirement date of the proposed subcategories, Talen recommends that EPA revise its proposed subcategories to ensure grid reliability and to further stakeholder collaboration. First, Talen asks EPA to consider modifying the definition of the subcategories such that each subcategory would be based on the date that a unit ceases to burn coal rather than ceasing operation altogether. This would encourage owners/operators of coal-fired units to explore other options, such as converting to natural gas or biofuel, and provide them with greater flexibility as to how to meet reliability requirements and to best make use of existing infrastructure and a unit's remaining useful life. Identifying the subcategories based on a unit's cease-to-use-coal date rather than its retirement date is important to allow such units to continue to operate given concerns that transmission expansion will not be sufficient to support increasing renewables over the next several years and that continued reliance on fossil fuel-fired EGUs may be necessary.[42] BSER for units converting from coal to gas should be routine methods of operation and maintenance, and they should be exempt from the proposed standards for existing gas-fired steam electric generating units until after the gas conversion is complete.

Further, EPA should clarify that states should be able to take a planned fuel switch into account in setting the emission standard for a particular unit, based on the state's authority to consider remaining useful life and other factors ("RULOF") so that even if the unit is categorized as a Near-, Medium- or Long-term unit, the default requirements for those subcategories would not apply. And, at the least, EPA should make clear to the states that they have authority to establish alternative standards for units converting from coal to gas in the period before the conversion is completed. Additionally, EPA should provide an emergency operation provision for a coal unit to bypass CCS or low-GHG co-firing if those technologies become non-functional and/or power demand is high.

Second, for the Imminent- and Near-term subcategories, EPA should allow units that fall into such subcategories the option to comply with mass emission caps (*e.g.,* annual mass

---

[42] *See* Jesse D. Jenkins et al., Princeton Univ. Zero Lab, *Climate Progress and the 117th Congress: The Impacts of the Inflation Reduction Act and Infrastructure Investment and Jobs Act* (July 2023), https://repeatproject.org/docs/REPEAT_Climate_Progress_and_the_117th_Congress.pdf (discussing how failure to increase transmission expansion in the United States "severely" limits potential wind, solar and energy storage projects, and the rate of current transmission expansions would have to double to meet the Biden Administration's net-zero target by 2035).

limitation), and allow states to adopt such an approach. The mass-based approach would allow for more flexibility in operation and could help account for future operational variability—*i.e.*, make units less vulnerable to exceeding a static emissions rate limit. Talen recommends that the mass emissions cap or emissions rate limit be a longer-term average of at least annual (alternatively, a 12-month rolling) value.

Third, while EPA stated in a Technical Support Document that "[c]oal-fired EGUs that convert entirely to burn natural gas are no longer subject to coal-fired EGU mitigation measures," and that the "[o]il/[g]as steam category includes coal to gas conversions,"[43] the regulatory text should make it clear to States how such units should be treated for purposes of their plans. EPA also should clarify that the coal-fired EGU requirements would no longer apply even if the gas conversion takes place at a date after January 1, 2030. In other words, states should have flexibility not to mandate a once-in, always in approach to the subcategories and their corresponding standards. Although the statement in the Technical Support Document and other statements in the Proposal indicate that EPA believes such flexibility is available, EPA should make this clear in the final rule. Such flexibility will assist EGUs with developing cost-effective compliance options.

C. EPA Should Not Establish 40 Percent Natural Gas Co-Firing as BSER for the Medium-Term Subcategory

For coal units that are not already co-firing natural gas, in many cases it will not be possible or cost effective to permit or construct gas pipeline infrastructure for the Medium-term subcategory. Such units would either be forced to retire prematurely—particularly if they operate as baseload units, in which case it would be uneconomical to operate with a 20 percent capacity limit—or install CCS. For such units, natural gas co-firing would not be an "in between" subcategory option. However, should EPA finalize the 40 percent gas co-firing requirement for the Medium-term subcategory, the compliance deadlines should be extended by at least five years to accommodate required permitting, approval, and construction of required equipment and infrastructure.

In response to EPA's request for feedback, Talen does not support a potential BSER based on low levels of natural gas co-firing for units in the Imminent- and Near-term subcategories because the technology is not feasible for units that do not currently have access to pipeline infrastructure, such as Colstrip. It also is not possible or cost effective to permit and construct new infrastructure within the implementation timeline proposed by EPA for the Imminent- and Near-term subcategories. This should not be a basis for setting emissions limitations for units in the Imminent- and Near-term subcategories.

D. EPA Should Not Establish CCS as BSER for the Long-Term Subcategory

For existing coal-fired EGUs in the Long-term subcategory, EPA has established CCS as BSER, with a compliance deadline of January 1, 2030. For several reasons, Talen is concerned with EPA setting CCS as BSER for this subcategory. First, as discussed *supra* Section III, Talen believes that EPA would exceed its statutory authority if the Agency required CCS as BSER.

[43] *See* Additional Modeling Memo, *supra* note 8, at 3 n. c.

Second, it would be nearly impossible for a prudent owner/operator of a Long-term unit to install and implement CCS by January 1, 2030 for the reasons articulated above. According to the Proposal, EPA expects the final emission guidelines will be published in June 2024, with a State plan submission deadline 24 months later and 14 months for EPA review and approval of the submitted state plans.[44]

According to the Agency, the planning, design, and construction of both the carbon capture system and the transport and storage system can be completed within five years.[45] That timeframe fails to match the proposed compliance deadline of January 1, 2030. A state plan submission deadline of 24 months, as proposed, would mean leaving less than three years after plan approval for detailed engineering, design, permitting, public service commission ("PSC") approval, construction, and commissioning of required equipment and infrastructure, including any required pipelines and new transmission lines. EPA cannot reasonably expect EGU owners/operators to begin expending material resources to plan, develop, and construct CCS before EPA has approved the state plan that specifies the scope of work and schedule.

Moreover, Talen is concerned that EPA may have severely underestimated the timeframe required to complete both systems given the factors involved. These factors include exploring and vetting of appropriate sequestration sites, procuring funding for operations and contractual arrangements, water availability and in turn the required additional authorization of water use, and land acquisition rights for a pipeline. Land acquisition rights may be particularly difficult where there is a patchwork of ownership.[46] Pipeline infrastructure also must allow for safety, biological, and cultural assessments pursuant to, for instance, the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), Endangered Species Act ("ESA"), the National Historic Preservation Act ("NHPA"), and the National Environmental Policy Act ("NEPA") regulations. Such assessments can vary greatly in timing and may take years depending on the amount and type of resources impacted and public opposition.

More importantly, EPA should not require the construction of CCS until PHMSA finalizes safety standards for construction of CO_2 pipelines, which, according to the Spring 2023 Unified Agenda, will not even be *proposed* until January 2024.[47] Pipeline infrastructure development

---

[44] *See* 88 Fed. Reg. at 33,372 ("The EPA expects that final emission guidelines will be published in June 2024 and is proposing a State plan submission deadline that is 24 months from publication which would be June 2026."). Talen urges EPA to extend the submission deadline for state plans from 24 months to 48 months given the Proposal's breadth and complexity.

[45] *See id.*

[46] *See* Jack Dura. *North Dakota Regulators Deny Siting Permit for Summit Carbon Dioxide Pipeline; Company Will Reapply*, AP News, Aug. 4, 2023, https://apnews.com/article/north-dakota-carbon-dioxide-pipeline-29d15d0d29782f9f28b7907b6bb1896e (proposed pipeline project that was ultimately denied due to landowner concerns of eminent domain and potential dangers of a pipeline break).

[47] *See* U.S. Dep't of Transp., Pipeline & Hazardous Materials Safety Admin., *PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak* (May 26, 2022), https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures#:~:text=WASHINGTON%20%2D%20The%20U.S.%20Department%20of,protect%20communities%20from%20dangerous%20pipeline; *see also* Office of Mgmt. & Budget, *Pipeline Safety--Safety of Carbon Dioxide Pipelines*, RIN: 2137-AF60, Publication ID Spring 2023, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2137-AF60.

extends far beyond the plant and must be built out across regions, which is estimated to total over 66,000 miles of pipeline.[48] Such development will require significant time to design, permit, and construct, particularly if pipelines are to be built in or near communities with environmental justice concerns. Electric generating companies are unlikely to be the pipeline operators, and the development of pipeline infrastructure likely is beyond the control of such companies as well.

Briefly stated, CCS projects require significant lead time and planning. CCS projects also require, among other complicated and time-consuming permits, a Class VI injection well permit for injecting CO_2 into the subsurface. Further, CCS projects would be dependent on the supply of available materials, equipment, and labor. Ultimately, EPA must be cognizant that the regulatory community affected by this Proposal own and operate *power plants*; the owners/operators are neither fuel producers, nor are they owners/operators of CO_2 pipelines and storages. Aside from the amine-based carbon capture projects that EPA identifies in the Proposal, which represent pilot-scale slipstream projects, the Talen requests that EPA identify any other *actual*, non-pilot-scale projects in the United States that are still in operation and that have demonstrated the long-term ability to consistently capture 90 percent of total CO_2 emissions from an EGU.[49] In the Proposal, EPA cites to, among others, the Shady Point Plant as an example of achieved and available CCS.[50] However, the Shady Point Plant is no longer in operation and, at the time of operations, was a small capture unit treating a small slip stream of flue gas from the generating units.

Third, Talen is concerned that EPA has not adequately analyzed potential community concerns, which could delay or otherwise impede state or local permitting processes and approvals, or challenges to states seeking authorization for Class VI permitting, thereby leading to delays or failure to obtain necessary permits to accommodate CCS. EPA also should issue rules or guidance related to plume migration of sequestered CO_2.

Fourth, if EPA finalizes CCS as BSER for the Long-term coal-fired steam generating unit subcategory, Talen requests that EPA account for the full landscape of permitting processes required to implement CCS (including, but not limited to, major or minor New Source Review ("NSR") or state permits that may require additional public notice), as well as the anticipated timeline thereof. Although, as noted above, Talen does not agree with the Agency that CCS should be established as BSER at this time since it has not been adequately demonstrated, if EPA finalizes CCS as BSER in the final emission guidelines, Talen requests that EPA extend the compliance deadline (potentially with an additional extension period if an accompanying, legitimate justification is also provided) to ensure that all of the issues associated with installing CCS and the associated infrastructure have been more fully resolved, or codify that states have authority to include in their plans additional time from the date that a state plan is approved by EPA, before compliance must be demonstrated.

[48] *See* Paul W. Parfomak, Cong. Rsch. Serv., IN11944, *Carbon Dioxide Pipelines: Safety Issues* (2022), https://crsreports.congress.gov/product/pdf/IN/IN11944.

[49] *See* 88 Fed. Reg. at 33,254.

[50] *See id.* at 33,392.

V. EPA SHOULD CLARIFY THE APPLICABILITY THRESHOLD DETERMINATION AND RECONSIDER BSER FOR LARGE, FREQUENTLY USED EXISTING FOSSIL FUEL-FIRED STATIONARY COMBUSTION TURBINES

The Proposal establishes a subcategory for large, frequently used existing fossil fuel-fired stationary combustion turbines and defines them as stationary combustion turbines that have an electric generating capacity greater than 300 MW and a capacity factor of greater than 50 percent, which primarily encompasses existing natural gas-fired combined cycle combustion turbines.[51] EPA is proposing two pathways as BSER for such combustion turbines: (1) use of CCS by 2035, or (2) co-firing of 30 percent by volume low-GHG hydrogen by 2032 and co-firing 96 percent by volume low-GHG hydrogen by 2038. For stationary combustion turbines selecting the CCS pathway, EPA is proposing that the presumptively approvable standard is an 89 percent reduction in the unit's annual baseline emission rate in lb CO_2/MWh-gross.[52] For stationary combustion turbines selecting the low-GHG hydrogen co-firing pathway, EPA is proposing that the presumptively approvable standard is a 12 percent reduction in the unit's annual baseline emission rate in lb CO_2/MWh-gross beginning January 1, 2032, and the presumptively approvable standard beginning January 1, 2038, is an 88.4 percent reduction in the unit's annual baseline emission rate in lb CO_2/MWh-gross.[53]

The Proposal requires the combustion of "low-GHG hydrogen." This is defined in proposed 40 C.F.R. Subpart TTTTa (which also would apply to Subpart UUUUb) as hydrogen that is "produced through a process that results in a GHG emission rate of less than 0.45 kg of CO_2 equivalent per kilogram of hydrogen (kg CO_2e/kg H_2) on a well-to-gate basis."[54] According to EPA, the proposed definition is consistent with the definitions used in the Internal Revenue Code ("I.R.C.") Section 45V under the IRA.[55]

A. Talen Supports the Methodology that EPA Used in the IPM Modeling for the Applicability Threshold Determination

The Proposal does not define the electric generating capacity or explain how it is determined for NGCCs, nor does the Proposal identify how to determine whether a stationary combustion turbine exceeds an annual capacity factor of 50 percent. In the FAQs Memo, EPA asserts that the 300 MW threshold includes (1) the electric generating capacity of the combustion turbine; and (2) the electric generating capacity of any associated steam turbines apportioned/prorated to the combustion turbine, where:

---

[51] *See id*. at 33,362.

[52] *See id.* at 33,366.

[53] *See id.* at 33,380-81.

[54] Proposed § 60.5580a.

[55] *See* 88 Fed. Reg. at 33,304; *see also* I.R.C. § 45V(b)(2)(D) (providing that the "applicable percentage" for calculating the amount of clean hydrogen production credit for any taxable year is 100 percent for "any qualified clean hydrogen which is produced though a process that results in a lifecycle greenhouse gas emissions rate of less than 0.45 kilograms of CO_2e per kilogram of hydrogen").

- For a simple cycle combustion turbine, the total heat input and total electric generating capacity of the unit is attributable directly to the fuel combusted (heat input, MMBtu/hr) and the electricity generated (capacity, MW);

- For a NGCC unit, the total heat input to the unit includes the fuel combusted in the combustion turbine and the fuel combusted in any associated duct burners; and

- For a NGCC unit, the electric generating capacity is based on the electric generating capacity of the combustion turbine and the prorated (apportioned) electric generating capacity of the steam turbine.[56]

But EPA's IPM modeling and RIA supporting information for the Proposal utilize a methodology for categorizing the capacities of existing NGCCs that differs from the methodology in the FAQs Memo.[57] Specifically, both the IPM model and RIA supporting information categorize existing NGCC units based on "Dispatchable Capacity MW," which appears to be the net generating capacity value of the combustion turbine, and "Average Capacity MW," and Talen supports that methodology.[58]

As applied to LMBE, which consists of two combustion turbines that are combined with one steam turbine (IPM Unit ID 1769), the Dispatchable Capacity MW listed in the IPM model and RIA supporting information for the facility is 594 MW.[59] The IPM model and RIA supporting information list the Average Capacity MW for the LMBE units as 198 MW, which is equal to 594 MW divided by 3 units—two combustion turbines and one steam turbine. Dividing the Dispatchable Capacity MW by the number of combustion and steam turbines is appropriate because it results in a generating capacity that more closely reflects that of each combustion turbine individually, as they are the primary sources of CO_2. Talen supports this methodology—or simply setting the threshold applicability based on the size of the individual combustion turbines—and agrees with EPA that LMBE is not subject to the proposed GHG emission guidelines because the LMBE combustion turbines are less than the 300 MW capacity threshold. Talen requests that EPA amend the FAQs Memo when finalizing the Proposal such that the FAQs Memo is consistent with the methodology used to determine Average Capacity in the IPM model and RIA supporting information.

However, should EPA adopt the approach in the FAQs Memo when finalizing the Proposal, the Agency must reissue the Proposal as it pertains to existing large, frequently operated stationary combustion turbines because EPA has likely grossly underestimated the number of existing NGCCs subject to the proposed GHG emissions guidelines.[60] Whereas the RIA identified an estimated 37 GW capacity of affected units, the methodology in the FAQs Memo likely would implicate 72.5 GW capacity of affected units, comprising of at least 79 gas-fired units that would

---

[56] FAQs Memo at 4.

[57] RIA Section 8 Impacts, Dkt. ID No. EPA-HQ-OAR-2023-0072-0043 RIA (posted, May 25, 2023) (Section 8, Attachment 2).

[58] *See id.*

[59] *See id.*

[60] *See id.*

be impacted by the Proposal and increasing total industry costs by 97 percent.[61] The final rule would be arbitrary and capricious if EPA adopts the approach in the FAQs Memo as it would be based on a fundamentally flawed analysis, and the Agency must reissue the Proposal with an updated RIA that accurately reflects the costs and impacts to the sector, EPA's rationale for establishing the 300 MW threshold, and a robust explanation of how the 300 MW threshold should be calculated.

Additionally, EPA appears to have allowed combustion turbines until July 1, 2031, to declare their subcategory applicability.[62] Talen supports the flexibility of determining applicability relatively close to the compliance dates to allow decisions to be made as far out as reasonable. However, it appears that States are required to include applicability of all their units in their plan to EPA, which would need to be submitted much earlier than 2031. Talen requests that EPA clarify that the State Plan would include only "draft" or "potential" applicability, and that owners/operators would not have to make a compliance filing and/or commitment until 2031, consistent with proposed § 60.5740b(a)(3)(iii).

B. EPA Should Reconsider BSER for Stationary Combustion Turbines

Talen strongly recommends that EPA reconsider BSER for existing stationary combustion turbines. BSER for existing sources should not be the same as BSER for new sources because costs are far greater for retrofits than for new builds. Further, Talen recommends that, if EPA retains (the not adequately demonstrated) CCS and low-GHG hydrogen co-firing as BSER for large, frequently operated existing stationary combustion turbines, the Agency should delay the proposed schedule for installation of these technologies to accommodate feasible time frames that allow for an orderly transition away from coal-fired generation and to provide adequate time for permitting, regulatory approvals, development of required infrastructure, construction, and commissioning.

1. EPA should not establish CCS as BSER given that CCS has not yet been "adequately demonstrated" for stationary combustion turbines

EPA should not set CCS as BSER for large, frequently used existing stationary combustion turbines. Talen is concerned that units would not be able to implement CCS by the proposed compliance date of 2035. First, there is a significant difference between requiring one or a few sources to adopt a particular technology versus an entire industry scaling up a technology that is still developing slowly. Materials procurement, engineering, testing, construction, installation, transportation of CO_2—and the related permitting, regulatory compliance, and land-rights acquisition for such infrastructure—take considerable time. Intellectual property rights also may need to be negotiated given the nascent state of technology. Additionally, these projects will require coordination of transmission infrastructure construction and generator outages/commissioning activities to maintain system reliability. Overall, these projects, while dependent on market conditions, geography (including geological conditions), public opposition,

[61] *See* Proctor, Darrell, *Emissions Rules Could Target More Gas-Fired Power Plants*, POWER, Jul. 20, 2023, https://www.powermag.com/emissions-rules-could-target-more-gas-fired-power-plants/?oly_enc_id=2238C4810912A8L.

[62] *See* proposed § 60.5740b(a)(3)(iii).

etc., could take anywhere between eight to ten years (once the technology is commonplace). In addition, regulatory approvals (such as from public service commissions) will be based on requirements specified in a final, approved state plan, which means the developmental timeframe would not even begin until after EPA issues final approval of the relevant state plan. Further, there are no existing provisions establishing long-term liability and financial assurance for sequestration sites. To avoid potentially significant future environmental liabilities, EPA first needs to establish a long-term liability, closure and post-closure care, and financial assurance process for CCS projects so that such projects are certified according to a consensus standard and can be constructed and operated in accordance with that standard prior to establishing CCS as BSER. And if a facility meets the criteria set forth in the consensus standard, the facility should be released from liability if carbon storage locations later turn out to have safety or environmental impacts at an unknown future date.

Second, given the nascent nature of these technologies, more research is needed, particularly for gas-fired stationary combustion turbines. There are geographic and geological limitations, in addition to constraints on water availability, that hinder CCS, and more research, development, and demonstration work is needed to determine whether CCS is a viable option for gas-fired stationary combustion turbines. For instance, if the geography or geology at the facility does not support CCS, the facility would have to transport CO_2 off-site, which presents additional technical challenges and safety concerns, along with expanded permitting and construction timeframes (all of which are concerns outside the fence line).

CCS has only been deployed on a handful of baseload coal-fired EGUs—two in operation in North America with only one in the United States.[63] However, research and testing of amine technologies for CO_2 removal on gas-fired stationary combustion turbines have only recently begun.[64] More importantly, it is unclear whether the variable operating conditions of gas-fired stationary combustion turbines can support CCS, much less at the level of CO_2 removal proposed by EPA as BSER. Such EGUs need to quickly respond to support more flexible electric generating scenarios, which entail a wide range of operating conditions, including high ramping rates, periods of minimum load operations, and the potential for multiple startups and shutdowns of the unit per day. Additionally, CCS technology would require energy from the combustion turbines to operate, which would decrease the efficiency of the combustion turbine and decrease the unit's contribution to serving load requirements for system reliability and potentially delay broader economy-wide decarbonization by reducing electrification opportunities. All of this needs further analysis.

---

[63] The one project in the United States where CCS had been deployed on a coal-fired facility, PetraNova, does not qualify as being commercially available as it is assisted by U.S. government subsidies. *See* 88 Fed. Reg. at 33,290-92 (acknowledging that the Agency is precluded from relying solely on the experiences of facilities that received funding). PetraNova also stopped operating because the price of oil recovered from the injection of CO_2 into oil wells was not sufficient to justify continued operation. EPA fails to point to any other information pertaining to CCS deployment in the United States that would show that the technology has been adequately demonstrated. Further, the other project identified in the Proposal, SaskPower's Boundary Dam Unit 3, is significantly smaller (1100 MW) than most coal-fired units—in contrast, Colstrip is over 13 times larger (1480 MW).

[64] EPA also refers to the Bellingham Energy Center in south central Massachusetts to demonstrate that CCS was "successfully applied to an existing combined cycle combustion turbine EGU." *See, e.g., id.* at 33,254. That facility was used in the 1990s primarily to serve the food industry and was far too small of a unit. It does not demonstrate feasibility for the scale that EPA is advocating.

Should CCS be adequately demonstrated prior to the proposed compliance date of 2035 for stationary combustion turbines, there are still multiple additional hurdles that may hinder the deployment of CCS within the proposed compliance timeframe. The measures proposed by EPA is not simply an add-on control. CCS requires significant retrofitting and engineering. For instance, CCS would substantially increase the costs associated with constructing a new gas-fired stationary combustion turbine facility, potentially making many such projects uneconomical. CCS technology also might require energy for directing steam from a NGCC's heat recovery system generators ("HRSGs") to the carbon capture unit.[65] This would require the stationary combustion turbine to fire more gas and produce a lower overall amount of net electricity for the grid, thus reducing the efficiency of the stationary combustion turbine as well as its ability to support grid reliability. Current research and engineering evaluations are focused on addressing this issue, but such results to date have not been demonstrated.

For these reasons, Talen reiterates that CCS for gas-fired stationary combustion turbines has not been "adequately demonstrated" to be BSER. But to the extent EPA finalizes a determination that it has, Talen strongly recommends that EPA include provisions to provide relief to sources in the event that necessary technology advancements and infrastructure deployment do not occur (such as automatic compliance deadline extensions/off-ramps if technology performance issues render achievement of the required emission standards infeasible) "by a date certain." A "date certain" would have to be sufficiently in advance of any compliance requirement to prevent the unnecessary spending of time, money, and resources, including on RTO planning requirements. Such backstop provisions would provide companies with needed certainty for making timely operational and investment decisions to meet the proposed compliance deadlines.

2. EPA should not establish low-GHG hydrogen co-firing as BSER given that the technology has not been adequately demonstrated

Low-GHG hydrogen co-firing is still under development and has yet to be proven at scale, let alone be commercially available. As a starter, storing hydrogen in tanks or geological formations is expensive and inherently inefficient due to energy losses from compression and re-expansion of the gas. There also will be a significant spike in water usage to produce hydrogen in the projected volumes—this includes hydrolyzed water, reject water, and cooling water. And, as of now, the energy to make hydrogen must be derived from *excess* renewables (in other words, only when production of renewable energy would be curtailed due to the lack of demand in real time) to be technologically and economically feasible. Finally, whatever small quantities of low-GHG hydrogen that could be created with excess renewables would first be directed at existing uses of hydrogen, such as ammonia production.

The status of the hydrogen economy illustrates Talen's position. Researchers at the National Renewable Energy Laboratory are currently working on challenges to accelerate low-GHG hydrogen production, which include: (1) improving fuel cell technology and materials needed for fuel cells; (2) development of technology to efficiently and cost-effectively make hydrogen from renewable sources and other non-carbon sources (such as nuclear); and (3) developing technology to efficiently and cost-effectively store and transport hydrogen.[66]

[65] *See id.* at 33,349.

[66] Nat'l Renewable Energy Lab, *Hydrogen Basics*, https://www.nrel.gov/research/eds-hydrogen.html.

Further, DOE is still in the process of reviewing applications for the Regional Clean Hydrogen Hubs (H2Hubs) program and has yet to even select awardees for funding.[67] Even DOE recognizes that there are challenges to low-GHG hydrogen that need to be resolved.[68] Accordingly, EPA must allow time for low-GHG hydrogen co-firing to advance and be adequately demonstrated to ensure reliable and consistent performance.

The projects referenced by EPA in the Technical Support Document, which involve co-firing of hydrogen in existing units largely include a couple of demonstration projects and a number of proposed projects that have not yet been completed.[69] There is limited data provided on the demonstration projects, particularly with regards to the duration of operation, which is important for understanding the long-term viability of the fuel since turbines will need to be able to consistently co-fire hydrogen. Furthermore, the proposed BSER of 96 percent low-GHG hydrogen co-firing by 2038 has not been demonstrated or proven to be achievable at an existing unit.[70] The hydrogen co-firing rates in the referenced demonstration projects range from 5 percent to 44 percent.[71] Therefore, adequate demonstration has not been achieved for hydrogen co-firing at the levels proposed by EPA, and EPA assumed that hydrogen co-firing would be available by the compliance dates without adequate demonstration.

In addition, EPA's proposed requirement that hydrogen co-firing be limited to low-GHG hydrogen is outside of the scope of Section 111(d) as applied to EGUs. EPA's proposal is directed at production of hydrogen, which is beyond the control of the electric generating plant. When a viable pipeline network for hydrogen production is developed, it is likely that hydrogen from a variety of processes will be commingled, and electric generators will not be able to certify that they have been supplied with low-GHG hydrogen. And hydrogen, no matter how it is produced, would not result in GHG emissions when burned at a stationary combustion turbine. The I.R.C. provides tax incentives for the production of low GHG-hydrogen that are likely to incentivize its production, which would support its use in hydrogen co-firing at stationary combustion turbines. To the extent additional regulation is needed to encourage the production of low-GHG hydrogen, EPA should direct any requirements related to the method of production to the fuel producers rather than the electric generating industry.

Nonetheless, if EPA intends to include co-firing of low-GHG hydrogen as BSER in the final emission guidelines, EPA should include all hydrogen at an intensity of 4.0 kg eCO_2/kg H_2 (as provided in the IRA and the Department of Energy's clean hydrogen policies) or lower to

---

[67] *See* U.S. Dep't of Energy, Office of Clean Energy Demonstrations, *Regional Clean Hydrogen Hubs*, https://www.energy.gov/oced/regional-clean-hydrogen-hubs-notifications#:~:text=The%20final%20application%20deadline%20is,well%20as%20related%20FAQ's%20below.

[68] *See generally* U.S. Dep't of Energy, *Pathways to Commercial Liftoff: Clean Hydrogen* (Mar. 2023), https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[69] *See* RIA Section 8 Impacts, Dkt. ID No. EPA-HQ-OAR-2023-0072-0043 RIA (posted, May 25, 2023) (Section 8, Attachment 2).

[70] *See id*. (referencing, for example, Brentwood Power Plant, which can co-fire 44 percent carbon-free hydrogen blended with natural gas; Georgia' Power's 2.5 GW McDonough-Atkinson Plant, which can co-fire 20 percent hydrogen blend at both full and partial loads; and Cricket Valley Energy Center, which is planning to co-fire 5 percent hydrogen blend).

[71] *See id.*

increase the eligible supply of low-GHG hydrogen. Production of low-GHG hydrogen at the scale needed for reliable combined cycle unit operations has not been achieved. Additionally, significant infrastructure development, including hydrogen pipeline construction, storage capacity, and adequate water supplies, would be needed to support low-GHG hydrogen generation. The Proposal cites to 1,600 miles of hydrogen gas pipelines being used in refineries along the Gulf Coast as proof that hydrogen pipelines can be built.[72] The Proposal, however, ignores several major concerns regarding hydrogen pipelines that must be addressed for safe transport.[73] These concerns include the high flammability range (to the point of potentially being explosive) of hydrogen and contamination issues for certain hydrogen odorants that are still being studied. EPA has not justified how hydrogen pipelines are safer than, or at least equivalent to, natural gas or oil pipelines such that proposed pipelines would not be cancelled or significantly delayed due to citizen push-back, particularly in communities with environmental justice concerns. Further, there currently is no federal body that approves the siting of dedicated hydrogen pipelines. This means that individual states must approve the construction of hydrogen pipelines, which complicates and extends the approval process for connecting these pipelines to regional hubs.

Aside from hydrogen pipelines, there are various concerns with low-GHG hydrogen co-firing, which even EPA acknowledges. To start, EPA understands there needs to be lead time for infrastructure to be built out to support low-GHG hydrogen co-firing.[74] The volumetric energy density of hydrogen (325 Btu/scf) is approximately three times lower than the volumetric energy density of natural gas (1,020 Btu/scf).[75] In addition to the transport and logistical challenges that this difference in volume will pose, the ability to retrofit existing NGCC units to fire a fuel with a heating value so fundamentally different from natural gas has not been adequately demonstrated and could result in reduced output of electrical energy from units which are retrofitted to co-fire hydrogen fuel.

Further, EPA acknowledges that a self-sustaining market for low-GHG hydrogen does not currently exist.[76] Additionally, should EPA finalize a determination that low-GHG hydrogen co-firing is BSER, EPA should make sure that this standard does not force sources to violate other CAA requirements, or at least make sure that compliance requirements are harmonized. In proposing to establish low-GHG hydrogen co-firing as BSER, EPA has acknowledged that co-firing has the potential to generate more thermal NOx emissions due to the increased flame temperature, which could be especially problematic in ozone nonattainment areas such as Los Angeles or Houston.[77] The majority of turbine models from General Electric ("GE") Gas Power, Siemens Energy, and Mitsubishi Heavy Industries are not currently capable of achieving 100 percent hydrogen capability. EPA states that manufacturers are developing dry low NO_X (DLN)

[72] *See* 88 Fed. Reg. at 33,313. The Proposal does not delve into the safety monitoring and protection systems installed for refinery hydrogen gas pipelines and, more crucially, whether they are desirable in non-industrial areas.

[73] Paul W. Parfomak, Cong. Rsch. Serv., R46700, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy* (March 2021), https://crsreports.congress.gov/product/pdf/R/R46700.

[74] *See* 88 Fed. Reg. at 33,361.

[75] *See* The Engineering ToolBox, *Fuel Gases – Combustion heat values for gases like acetylene, blast furnace gas, ethane, biogas and more – Gross and Net values*, https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html, https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf.

[76] *See* 88 Fed. Reg. at 33,365.

[77] *See id.* at 33,364.

combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NOx.[78] However, the evolution of control technology for turbine NOx emissions has been known to occur over the course of decades. GE, Siemens, and Mitsubishi are aiming to develop 100 percent DLN hydrogen combustion capability in the next decade, but until it is demonstrated, this issue poses a significant risk with respect to CAA compliance.[79] Hence, not only does technology involving retrofit of existing NGCC to co-fire hydrogen need to be adequately demonstrated, but technology for NOX control also needs to be adequately demonstrated for low-GHG hydrogen co-firing to be BSER. Low-GHG hydrogen co-firing also has the potential to result in capacity degradation, in addition to increased water use. Moreover, if additional controls are necessary as a result, this would exacerbate the capital cost passed on to customers.

There are several issues associated with low-GHG hydrogen co-firing at gas-fired stationary combustion turbines that are not addressed in the Proposal. Talen requests EPA to address the following questions:

- How has EPA determined that production and distribution of low-GHG hydrogen will be sufficiently advanced for sources to meet the proposed compliance dates?

- As levels of hydrogen combustion increase, combustion turbine output decreases. Has EPA accounted for the increased need for generation to offset this loss and its subsequent emissions? Can such emissions be addressed with combustor design modifications?

- How are start-up and shut-down emissions treated? And given how increased cycling would be needed to support intermittent renewable generation, has EPA calculated the subsequent overall emission impact of the increased reliance on combustion turbines?

- Given that hydrogen burns at a much higher temperature than natural gas, has EPA determined whether existing stationary combustion turbines, which may not have been built with metals capable of tolerating higher temperatures, can accommodate hydrogen without damage?

- Transporting high purity hydrogen can lead to hydrogen embrittlement of piping and infrastructure. This is an issue that needs to be fully resolved prior to low-GHG hydrogen co-firing being mandated. EPA broadly claims that this issue "can be mitigated through deployment of new pipeline infrastructure designed for compatibility with hydrogen in support of a new combustion turbine installation."[80] What is the basis for EPA's expectation that such pipeline infrastructure can be deployed in time for sources to meet the compliance deadlines?

---

[78] *See id.* at 33,312.

[79] *See* POWER, *High-Volume Hydrogen Gas Turbines Take Shape*, (May 1, 2019) https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/; Sonal Patel, *Siemens' Roadmap to 100% Hydrogen Gas Turbines*, POWER (July 1, 2020) https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/; Frederic Simon, *EGE eyes 100% hydrogen-fuelled power plants by 2030*, EURACTIV (May 20, 2021) https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.

[80] 88 Fed. Reg. at 33,314.

- Will increased hydrogen production affect gas compression equipment energy requirements? Will pushing a "less dense" gas or gas blend require compressor stations to operate more? Aren't most of those compressor stations gas-fired? Even if the stations are electric, won't the parasitic load increase?

- Has EPA considered the non-air environmental impacts of the amount of water consumption necessary (*e.g.*, cooling, production losses) to achieve the requisite level of low-GHG hydrogen production to enable the widespread adoption of low-GHG hydrogen co-firing within the EGU sector, and how that may strain states with limited water resources?[81]

- Has EPA considered the energy loss in generating electricity to create hydrogen through electrolysis, storing the hydrogen, and then re-converting it to electricity (known as "round-trip" efficiency), which can be significant?[82]

- Has EPA determined whether low-GHG hydrogen production systems can respond to changing levels of demand, as stationary combustion turbines operate in response to public electricity demand, which can vary significantly during 24 hours, as well as weekly, monthly, and seasonally?

- Would requirements for co-firing of low-GHG hydrogen be exempted during back up operations, such as stationary combustion turbines that operate on a back-up fuel like distillate oil when natural gas is curtailed?

- Is EPA aware of any studies that have shown that co-firing low-GHG hydrogen with fuel oil operation is possible?

For the above reasons, similar to its position on CCS, Talen strongly recommends that hydrogen co-firing not be established as BSER because the technology has not been "adequately demonstrated" as such—or, at a minimum, extend the compliance deadline for co-firing 30 percent hydrogen to 2035. However, should EPA finalize the BSER as proposed, relief should be provided to sources if the necessary technology/infrastructure/low-GHG hydrogen development does not occur "by a date certain" (such as automatic compliance deadline extensions/off-ramps if technology performance issues render achievement of the required emission standards infeasible). A "date certain" would have to be sufficiently in advance of any compliance requirement to

---

[81] *See* Milind Deo et. al., *Hydrogen Electricity Generation and Water Consumption Comparisons*, Energy & Geoscience Institute at the University of Utah, (2022) https://le.utah.gov/interim/2022/pdf/00004284.pdf.

[82] *See* Tom DiChristopher, *Hydrogen Technology Faces Efficiency Disadvantage in Power Storage Race*, S&P Global Market Intelligence (June 24, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/hydrogen-technology-faces-efficiency-disadvantage-in-power-storage-race-65162028#:~:text=While%20the%20production%20and%20storage,Institute%20for%20Energy%20Economics%20and; *see also* Green Car Congress, *DOE Reports Say Cumulative Investment in Hydrogen, Nuclear and Long-Duration Energy Storage Must Increase to $300B by 2030* (Mar. 23, 2023), https://www.greencarcongress.com/2023/03/20230323-pathways.html#:~:text=If%20water%20electrolysis%20dominates%20as,is%2050%20MMTpa%20by%202050 ("[U]p to 200 GW of new renewable energy sources would be needed by 2030 to support clean hydrogen production.").

prevent the unnecessary spending of time, money, and resources, including on RTO planning requirements. This would provide companies much needed certainty for making operational and investment decisions to meet the proposed compliance deadlines.

Further, should EPA finalize any standards for large, frequently used existing gas-fired stationary combustion turbines, EPA should provide similar latitude for such units as that provided for existing coal-fired units in the Imminent- or Near-term subcategories (discussed in Section IV, *infra*). Specifically, EPA should establish subcategories for large, frequently operated combustion turbines that intend to retire in the imminent- or near-term based on the dates for coal-fired EGUs and set BSER for such subcategories as routine methods of operation and maintenance.

VI. EPA SHOULD NOT ESTABLISH PRESUMPTIVELY APPROVABLE STANDARDS OR EMISSION LIMITS THAT ARE TOO RESTRICTIVE FOR EXISTING GAS-FIRED AND OIL-FIRED STEAM GENERATING UNITS

The Proposal would establish subcategories of existing gas-fired and oil-fired steam generating units by load level: (1) "Low" (annual capacity factor less than 8 percent); (2) "Intermediate" (annual capacity factor greater than or equal to 8 percent and less than 45 percent); and (3) "Base" (annual capacity factor equal to or greater than 45 percent. Aside from Low load levels, the BSER for existing gas-fired and oil-fired steam generating units is routine methods of operation and maintenance. EPA is not proposing BSER requirements for Low-load units.[83]

For existing Base- and Intermediate-load continental oil-fired and gas-fired steam generating units, the Proposal would require a no increase in emission rate.[84] The Proposal also would establish a presumptively approvable standard of performance annual emission rate limit of 1,300 lb CO_2/MWh-gross for base-load continental units and 1,500 lb CO_2/MWh-gross for intermediate-load continental units.[85] EPA is soliciting comments on establishing a presumptively approvable standard of performance in the ranges of 1,250 lb CO_2/MWh-gross to 1,800 lb CO_2/MWh-gross for base-load continental oil-fired units, 1,400 lb CO_2/MWh-gross to 2,000 lb CO_2/MWh-gross for intermediate-load continental oil-fired units, 1,250 lb CO_2/MWh-gross to 1,400 lb CO_2/MWh-gross for base-load natural gas-fired units, and 1,400 lb CO_2/MWh-gross to 1,600 lb CO_2/MWh-gross for intermediate-load natural gas-fired units.[86]

In addition to Colstrip and LMBE, Talen owns various gas- and oil-fired steam EGUs of various sizes. Units that are likely to be impacted by the Proposal and fall in the existing gas-fired and oil-fired steam generating unit (low- and intermediate-, and potentially baseload) subcategories include:

- The H.A. Wagner Generating Station ("Wagner") near Baltimore, Maryland, which has an operating capacity of 827 MW. Units 1 and 4 are existing oil-fired units, and Unit 3 is

[83] *See id.* at 33,360 (Table 5).

[84] *See id.*

[85] *See id.*

[86] *See id.*

being converted from coal-fired to oil-fired. Unit 3 is an efficient supercritical boiler and may run more frequently than the other units once converted.

- Brunner Island Steam Electric Station in York Haven, Pennsylvania, which has an operating capacity of 1,424 MW and where Units 1, 2, and 3 currently have coal- and gas-firing capabilities. The units will be required to burn only gas by January 1, 2029, and Talen anticipates the units will either fall under the intermediate- or base-load gas-firing unit subcategory.

- Montour Steam Electric Station in Washingtonville, Pennsylvania, which has an operating capacity of 1,508 MW and where Units 1 and 2 currently have coal- and gas-firing capabilities. The units will solely fire gas by January 1, 2026, and Talen anticipates the units will either fall under the intermediate- or base-load gas-firing unit subcategory.

- Barney Davis Power Plant in Corpus Christi, Texas, which has an operating capacity of 897 MW, including two combustion turbines and a gas-fired steam EGU (Unit 1). Talen anticipates Unit 1 falling under the low-load gas-firing unit subcategory.

- Martins Creek Power Plant ("Martins Creek") in Bangor, Pennsylvania, where Units 3 and 4 currently operate as dual fuel-fired units, firing both natural gas and fuel oil. Each unit's capacity is approximately 700 MW when the units are firing solely natural gas and 850 MW when the units are firing either some or solely fuel oil.

Talen requests that EPA eliminate presumptively approvable standards of performance and reconsider having an emission limitation of zero percent increase over a prescribed baseline emission rate. Routine methods of operation and maintenance should be sufficient because there is no available means of controlling CO_2. The CO2 emission rate is largely only affected by the load range in which the unit is operating, which in turn depends on how the unit is being dispatched by a RTO, such that there is no control over the CO2 emission rate. EPA in fact acknowledges that when a unit is operating most efficiently—where the CO_2 emission rate is at the lowest—the unit operates at full load.[87] Units at low load operate less efficiently—where the CO_2 emission rate is higher—when it needs to be on standby and available for dispatch when called upon by an RTO to ramp up generation. Thus, such dispatchable units, which operate at times essential to maintain grid reliability, inevitably have CO_2 emission rates that are significantly less predictable. Even when measured on an annual average basis, the rate can be affected by unit outages, transmission line outages, weather, and fuel prices.

Talen is concerned with EPA's proposal to establish CO_2 emission limits because such limits fail to account for various shifts in the electric generating sector. For instance, future electric generating profiles are unlikely to reflect the historic generating profiles for most units in light of the transition to renewable generation, the shift to electrification and shifts in geographic populations. Units thus are unlikely to be operating in the same way in 2030 as in 2020. As renewable generation becomes more robust, gas- and oil-fired steam generating units would likely operate at lower loads, where more starts and stops will result in less efficient operation and higher, future CO_2 emission rates. While the total mass of CO_2 emitted annually would likely decrease in

---

[87] *See id.* at 33,278.

the future, individual units, however, are likely to be in noncompliance by exceeding the limit of zero percent in emission increase required by the Proposal. EPA should thus not go beyond requiring routine methods of operation and maintenance for oil and gas units.

Should EPA finalize the Proposal with CO_2 emission limits, Talen requests that EPA adopt the higher end of the presumptively approvable standards of performance the Agency is seeking comments on. Specifically, EPA should establish 1,800 lb CO_2/MWh-gross for base-load continental oil-fired units, 2,000 lb CO_2/MWh-gross for intermediate-load continental oil-fired units, 1,400 lb CO_2/MWh-gross for base-load natural gas-fired units, and 1,600 lb CO_2/MWh-gross for intermediate-load natural gas-fired units.[88] The presumptively approvable standards of performance that EPA is proposing are likely too restrictive, especially for the oil-fired units. Talen has oil-fired units, and although they may not have a capacity factor greater than eight percent, their CO_2 emission rate (lb/MWh) when operating close to full load should represent a minimum emission rate. For instance, based on recent data, Talen's Wagner Units 1 and 4, which fire oil, emit approximately 1,850 lbs CO_2/MWh and 1,950 lbs CO_2/MWh respectively when it is operating at more than 90 percent of full load.

Furthermore, should EPA finalize the Proposal with CO_2 emission limits, Talen requests that EPA provide operational flexibility in establishing a zero percent increase in emission rate as the degree of emission limitation for the intermediate- and baseload oil- and gas-fired steam generating units. Talen is concerned that the requirement fails to account for need for flexibility required to ensure grid reliability and affordability, particularly because (1) these units will operate under different load profiles in the future than in the past; (2) there is no "dial" to reduce CO_2 emissions; and (3) the unit load, which is typically the only indicator of higher or lower CO_2 emission rates, is primarily controlled by RTO dispatch.

The requirement also fails to account for the variability in operation faced by dual fuel-firing units like Martins Creek, where emission rates may increase if more fuel oil is fired in a given year. Under the proposed definitions and based on recent historic operations, Martins Creek would likely be considered a gas-firing unit because it primarily burns gas (up to 700 MW of its ~850 MW capacity) and has historically burned less than 15 percent oil in any given year. To achieve full load, Martins Creek will need to burn some oil every year, and if natural gas is curtailed during cold winter days, the units will burn 100 percent oil. Whether Martins Creek's units burn 1 percent oil or 14 percent oil in any given year is driven by the demand on the grid (often weather-based) and the RTO. Talen is thus concerned that if the unit-specific emission rate baseline is determined by the years when only 1 percent oil was burned, then any given year where the units burn a higher percentage oil will result in noncompliance by exceeding the zero percent emission rate limitation.

In establishing the unit-specific baseline of emission performance, proposed § 60.5775b(d)(1) currently provides that:

> A state shall use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from the most representative continuous 8-quarter period from 40

[88] *See id.* at 33,360 (Table 5).

> CFR part 75 reporting within the 5 years immediately prior to [INSERT DATE OF PUBLICATION OF FINAL RULE].

EPA should provide states with greater flexibility in considering other time frames besides the five years immediately prior to the date of publication of the final rule that more accurately reflect potential/future operating conditions. For example, EPA should change the commencement of the lookback period to commence well after the date of publication of the final rule. EPA also should provide states with greater flexibility in selecting which quarters or other time periods are within the selected time frame that better reflect potential operating conditions. Additionally, the unit-specific baseline of emission performance should actually reflect a unit's worst-case emissions rate, while routine methods of operations and maintenance are being employed. Furthermore, EPA should provide a "safety valve" exempting units for increases in emission rate, as a result of grid reliability emergencies or concerns.

VII. CONCLUSION

Talen appreciates the opportunity to submit comments on the Proposal. Talen urges EPA to consider the recommendations above in light of the significant impacts the Proposal will have on the electric generating sector, and, more crucially, on how Talen can continue to provide safe, reliable, and affordable electricity.

Dated: August 8, 2023

Respectfully submitted,

/s/ Thomas Weissinger

Thomas Weissinger
Sr. Director – Environmental
Talen Energy
thomas.weissinger@talenenergy.com

August 8, 2023

Via Federal eRulemaking Portal [regulations.gov]

EPA Docket Center
Environmental Protection Agency
Air and Radiation Docket and Information Center
Docket ID No. EPA-HQ-OAR-2023-0072

Re: NorthWestern Corporation Comments on: 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; Proposed Rule

Docket ID No. EPA-HQ-OAR-2023-0072

Dear Docket Staff:

On behalf of NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern"), I am commenting on the U.S. Environmental Protection Agency's ("EPA's") proposed 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. The proposal was published in the *Federal Register* at 88 Fed. Reg. 33,240 (May 23, 2023) ("Proposed Rule"). While NorthWestern supports the objective of promoting development and implementation of carbon capture, utilization, and sequestration ("CCUS"), as discussed herein, the Proposed Rule is premature and unlawful.

NorthWestern agrees with and incorporates by reference the concurrent comments submitted by the Edison Electric Institute ("EEI"), of which NorthWestern is a member, and Talen Montana, LLC ("Talen") as part owner and based on its knowledge as operator of Units 3 and 4 of the Colstrip Steam Electric Station ("Colstrip").[1] NorthWestern also agrees with the comments by Otter Tail Power Company ("Otter Tail").[2] NorthWestern and Otter Tail are co-owners of the Big Stone Plant in South Dakota and Coyote Station

[1] NorthWestern makes clear that when it discusses the future management of Colstrip, including the feasibility of CCUS or various closure scenarios, NorthWestern is speaking only for the share of Colstrip that it owns or will own.

[2] NorthWestern specifically notes its agreement with Talen's and Otter Tail's objections to the insufficient time afforded to comment on a proposed rule of this magnitude.

Electric Generating Unit in North Dakota. NorthWestern endeavors to minimize duplication of the EEI, Talen, and Otter Tail comments.

These comments are organized into the following sections:

1. Summary of Comments;

2. NorthWestern's commitment to environmental and climate responsibility, including support for development of CCUS;

3. NorthWestern's commitment to Environmental Justice;

4. The Proposed Rule is subject to scrutiny under the Major Questions Doctrine;

5. Interaction between the Proposed Rule and Proposed MATS Rule Update;

6. Colstrip exemplifies why CCUS cannot be considered a Best System of Emissions Reduction for existing coal-fired EGUs under applicable law;

7. The Proposed Rule poses substantial risks of adverse environmental and human welfare outcomes;

8. Many of the statutory financial incentives may not be available;

9. Grid management by importation and emergency order is not an acceptable state of affairs; and

10. Requests.

Each of these subjects is addressed below.

1. Summary of Comments

The Proposed Rule does not comply with the Clean Air Act, and is technically and practically unsustainable. NorthWestern is a leader among utilities nationwide in achieving carbon emission reductions and committing to major future reductions. Indeed, NorthWestern has been so successful that it has reduced its fossil fuel reliance to the bare minimum needed to maintain reliable electrical service, and to best integrate renewables. NorthWestern is also presently on a path to close its primary facility in Montana that would be subject to the Proposed Rule – Colstrip – by 2042. NorthWestern also supports continued development of carbon capture technology.

But NorthWestern's progress, as well as the progress of utilities in surrounding states, has only made NorthWestern especially vulnerable to the Proposed Rule and unable to substantially accelerate Colstrip's closure. NorthWestern and its customers are thus postured to bear the full force of the Proposed Rule.

The Proposed Rule is unrealistic in every dimension, including cost, achievability, timing, technical performance, and environmental and human consequences. NorthWestern relies on other parties, such as the EEI, to articulate the issues with the Proposed Rule on a national scale. In Section 6 of these Comments, NorthWestern offers the concrete example of CCUS as potentially applied to Colstrip to illustrate these issues in the context of a specific facility. Colstrip is located in a place where CCUS may theoretically be among the more implementable in the country, because of relative proximity to oil and gas fields where carbon dioxide ("CO_2") captured from Colstrip's emissions could potentially be sequestered. However, the realities of designing, permitting, constructing, and operating CCUS at Colstrip, as supported by the Department of Energy (see Section 6.a below) and other recent experience, demonstrates that EPA's estimates of timelines, costs, and performance of the various equipment associated with an integrated CCUS system are simply incorrect.

Each of the Proposed Rule's various subcategories are infeasible for Colstrip. As noted, the presently assessed Remaining Useful Life of Facility ("RULOF") Colstrip is 2042, which would place Colstrip in the "Long term" Subcategory in the Proposed Rule. This would require Colstrip to achieve a 90% CO_2 capture rate by 2030. The following briefly summarizes why compliance with the Proposed Rule in the Long term subcategory is not achievable or cost-effective, and why the other proposed subcategories are also infeasible and not cost-effective.

Long term Subcategory – As discussed in the EEI and Otter Tail comments, and Section 6 of these comments in relation to Colstrip, capture rates in the 90% range at existing facilities have not been adequately demonstrated. In 2018, the Department of Energy assessed that only a 63% capture rate was reasonably attainable at Colstrip, and that would be at a cost of $1.3 billion dollars and $100 million in annual operating costs. In addition, Colstrip cannot reasonably be retro-fit with a CCUS system by the proposed January 1, 2030 deadline. A CO_2 pipeline to potential sequestration sites alone is highly unlikely to be designed, permitted, constructed, and commissioned for operation in less than a decade, and would cost hundreds of millions of dollars.

Medium term Subcategory – The "Medium term" subcategory would require an enforceable closure commitment for no later than January 1, 2040, <u>and</u> installation of co-fired natural gas to supplant at least 40% of Colstrip's capacity by January 1, 2030. The Medium term subcategory is infeasible for Colstrip because a new natural gas pipeline would be required that cannot reasonably be expected to be operational by January 1,

2030. In addition, the cost of such a pipeline and retrofitting Colstrip for natural gas co-firing are prohibitive, both in absolute terms (exceeding $1 billion), and in light of the maximum ten year lifetime of those improvements.

Near term Subcategory – This subcategory requires a commitment to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, effective no later than January 1, 2030. This lifespan is too short given the irreplaceable role Colstrip presently plays in NorthWestern's portfolio. In addition, Colstrip presently operates at over 70% capacity. It is not feasible to reliably or cost-effectively replace the loss of so much of Colstrip's capacity by January 1, 2030.

Imminent Subcategory – The "Imminent" subcategory requires enforceable closure by January 1, 2032. This is infeasible for the same reasons the Near term subcategory is infeasible.

As discussed in Section 7, even if NorthWestern were somehow able to install CCUS within the deadlines of the Proposed Rule, the net effect would be extend Colstrip's life and create a substantial risk that net environmental impacts would be worse than if the Proposed Rule is not finalized.

Section 8 explains that the financial incentives EPA relies on to conclude that the Proposed Rule can be implemented a reasonable net cost are likely not achievable and carry too much uncertainty for prudent utility planning.

Finally, Section 9 observes that the Proposed Rule poses severe risks for electrical grid stability and chaotic management by emergency order, which an unwise and unsustainable regime.

Consequently, NorthWestern respectfully urges EPA to use its discretion under the Clean Air Act and Executive Orders 13990 and 12898 to take the following actions:

(1). EPA should withdraw the Proposed Rule until technological developments that could sustain national CCUS implementation have occurred; or

(2). If rulemaking proceeds, EPA should materially extend the compliance deadlines and lower the carbon capture requirements; and

(3). If rulemaking proceeds, EPA should also create an opt-out option for facilities that decide, within one year of the publication of the Final Rule, to enforceably commit to closure by December 31, 2035.

The foregoing courses of action are the only options that comply with the statutory requirements of the Clean Air Act, and are consistent with the objectives of E.O.s 13990 and 12898.

2. NorthWestern's commitment to environmental and climate responsibility

NorthWestern is a strong proponent of environmental protection, consistent with its responsibilities to deliver reliable, cost-effective electrical service to its customers. To that end, NorthWestern has a corporate objective to achieve net zero emissions by 2050. A copy of NorthWestern's "Net Zero by 2050" document is attached as Exhibit A. NorthWestern's 2022 Sustainability Report, which provides an update on progress toward Net Zero objectives, is attached as Exhibit B. NorthWestern already has one of the highest percentages of carbon-free generation in the United States, and has significant additional carbon and other emissions-reducing projects in development. Although NorthWestern disagrees strongly with the Proposed Rule in its current form, this should not be confused with opposition to carbon emissions reduction or the objectives of E.O. 13990.

In particular, NorthWestern notes the following:

- 56% of NorthWestern's energy supply portfolio[3] is already carbon-free;

- NorthWestern is committed to cease adding carbon-emitting generation by 2035;

- NorthWestern has committed to close out its interests in its coal facilities when they are depreciated or no longer cost-effective – presently forecast to be 2042 for Colstrip; and

- NorthWestern is making very substantial investments in energy efficiency, advanced metering, methane leak detection, electric vehicles, and transmission improvements, all to reduce NorthWestern's carbon footprint.

Indeed, one of NorthWestern's principal concerns with the Proposed Rule is that it will impair progress toward Net Zero objectives. As discussed further in these comments, NorthWestern cannot presently meet statutory mandates for reliability without Colstrip, and this will remain true for at least the next 12-15 years. Finalization of the Proposed Rule with its current compliance deadlines could force NorthWestern into investing huge sums into installing unproven CCUS technology on Colstrip. This could not only extend Colstrip's life (and emissions), but divert resources from a variety of carbon-reducing investments that NorthWestern has planned to make as part of its Net Zero initiative.

[3] As a percentage of total MWh delivered.

3. NorthWestern's commitment to Environmental Justice

NorthWestern shares the Administration's commitment to Environmental Justice. NorthWestern has extensive programs supporting critically needed affordable and reliable energy for low income and tribal communities within NorthWestern's service area. It is not clear from the Proposed Rule and supporting documentation that EPA has fully considered the distributive Environmental Justice consequences of the Proposed Rule, especially as related to Montana and the Environmental Justice communities in Montana. For example, 25% of NorthWestern's customer base is low income, with approximately half of those below poverty standards. The extraordinary costs of the Proposed Rule will fall on those who are least able to afford it, and the grid reliability dangers posed by Proposed Rule also threaten the most vulnerable in Montana.[4] In addition to the essential services NorthWestern provides, Colstrip and the Rosebud Mine supplying Colstrip directly employ 82 people of tribal affiliation, or 14% of the facilities' total employment. Premature closure of Colstrip would devastate these families and the Colstrip community as a whole.

The Environmental Justice dimensions of the Proposed Rule are particularly challenging, in that the harms of GHG emissions, by the very nature of climate change and the structure of the Social Cost of Carbon ("SCC"), are globally focused, while the burdens land squarely on local populations. To the extent EPA points to SCC estimates as a benchmark for the benefits of the Proposed Rule, it must be remembered that the SCC is an estimate of the *global* cost of emitting (and benefit of not emitting) a ton of carbon, whereas the extremely high costs of retrofitting Colstrip to implement CCUS, or closing Colstrip prematurely, are concentrated on the residents of Montana and will be felt most intensely by its most vulnerable citizens and small businesses.

As shown by NorthWestern's NetZero by 2050 commitment and NorthWestern's 2023 Integrated Resource Plan ("2023 IRP"), NorthWestern has made very aggressive monetary commitments to reduce its carbon footprint, at considerable cost to its customers. There are significant equitable and Environmental Justice consequences to adding *billions* of dollars of additional costs to these customers to attempt to accelerate achievement of net zero carbon emissions by a few years, if in fact net zero carbon emissions is achievable after the diversion of resources from existing Net Zero initiatives that would be precipitated by the Proposed Rule.

[4] Loss of electric power triggers hazards that vulnerable populations struggle to mitigate. *See e.g.*, https://www.sciencedirect.com/science/article/pii/S2212420922007208.

4. ***The Proposed Rule is subject to scrutiny under the Major Questions Doctrine***

The Proposed Rule is a response the Supreme Court's decision in *West Virginia v. EPA,*[5] in which the Court vacated the Clean Power Plan. As with the Proposed Rule, the Clean Power Plan was promulgated under Clean Air Act Section 111(d), a previously seldom-used "gap filler" provision.[6] The Clean Power Plan was premised on EPA's conclusion in 2015 that CCUS was *not* the Best System of Emission Reduction ("BSER") for existing sources; rather, only a "generation shifting" approach could attain EPA's climate change mitigation objectives, consistent with the multiple factors to be considered under Section 111, including cost, reliability, achievability, and other environmental and non-environmental factors.[7] The Court concluded that Congress did not clearly confer authority for such an expansive application of regulatory authority, and absent a clear delegation, the Clean Power Plan could not be sustained.

In concluding that CCUS is *now* the BSER for both existing coal-fired EGUs and new natural gas fueled EGUs, EPA is nominally returning to a more traditional technology-based regulatory approach focused on individual sources, as directed by the Court.[8] But that does not insulate EPA from examination under the Major Questions Doctrine. In particular, the Court in *West Virginia* identified three key factors that trigger Major Questions scrutiny:

- The regulation concerns "vital considerations of national policy";[9]
- Implicating issues "not within [the agency's] traditional expertise";[10] and,
- Involving a novel or newly expansive interpretation of agency authority.[11]

Also relevant is whether Congress "considered and rejected" the approach now advocated by the agency.[12]

---

[5] 142 S.Ct. 2587 (2022).
[6] *West Virginia*, 142 S.Ct. at 2610.
[7] *Id.* at 2612.
[8] *Id.* at 2611.
[9] *Id.* at 2612; *see also Biden v. Nebraska,* 143 S.Ct. 2355, 2373 (2023)(highlighting the "economic and political significance" of the regulatory action under review).
[10] *Id.* at 2612-13.
[11] *Id.* at 2611.
[12] *Id.* at 2614.

The first two factors are clearly present with the Proposed Rule. The Proposed Rule concerns the exact same critical sector of the economy and national policy implications as the Clean Power Plan. Equally, the Proposed Rule continues to directly relate to "Understand[ing] and project[ing] system-wide . . . trends in areas such as electricity transmission, distribution, and storage," which are outside EPA's traditional expertise.[13] Indeed, in some respects the Proposed Rule strays further beyond EPA's expertise than the Clean Power Plan, because the Proposed Rule depends critically on integration of the site-specific carbon capture process with long-distance pipeline transport and storage of captured CO_2, implicating an entirely new set of expertise and authority beyond the site itself.

Although the Proposed Rule is less radical than the Clean Power Plan in that it attempts to require individual sources to operate "more cleanly" rather than engage in wholesale generation shifting,[14] there remain entirely unprecedented dimensions to the Proposed Rule. These include, as EEI discusses in detail, "phased implementation" of standards applicable to new natural gas fueled EGUs, mandating pollutant recovery rates far in excess of anything that has been consistently and sustainably achieved in commercial application, and determining the feasibility of BSER based on its individual constituent parts, rather than performance as an integrated system. Individually and collectively, these interpretations of the agency authority constitute every bit as much an expansive interpretation of agency authority as triggered Major Questions scrutiny in *West Virginia*.

Notably, both *Congress* and *EPA* itself have recently "considered and rejected" carbon capture as BSER. In enacting the Inflation Reduction Act ("IRA") just last year, Congress recognized that CCUS is a developing technology, and expressly took an approach of incentivizing the development of renewables and carbon management, rather than mandating implementation of CCUS on any particular timeframe. There is simply no evidence in the IRA that Congress anticipated or authorized the EPA to promulgate anything like the Proposed Rule. This is perfectly understandable, because EPA itself had determined that CCUS was *not* BSER just seven years prior, and demonstration CCUS projects to date have been littered with operational problems, underperformance in carbon capture, and failing economics. EEI and Otter Tail provide detailed discussions of the Boundary Dam, Petra Nova, and other CCUS projects, none of which show that the technology can be reasonably considered BSER for utility-scale coal-fired EGUs. The Proposed Rule reflects a complete transformation of the Agency's view of the feasibility of the technology in just eight years.

Also critical is the fact that the "generation-shifting" at issue in *West Virginia* has not gone away, and in some ways the Proposed Rule creates even more extreme shifting. Recognizing that CCUS for coal-fired EGUs at the time was not demonstrated to be

[13] *Id.* at 2612.
[14] *Id.* at 2599.

feasible and was cost prohibitive, EPA proposed that climate objectives and Section 111 compliance could be achieved by shifting from one form of established baseload fossil fuel generation technology – coal-fired EGUs – to another – natural-gas fueled EGUs. Despite the significant differences between the technologies, both are capable of providing reliable, consistent, high-volume generation as needed to support a utility's generation portfolio.

The Court held that forcing such a shift exceeded EPA's authority. Here, EPA is simultaneously proposing to require CCUS for both coal *and* natural gas fueled EGUs. Consequently, if rulemaking proceeds as proposed, to the extent a utility concludes CCUS is cost-prohibitive or infeasible for its coal-fired EGUs under its specific circumstances, which as explained below is true for Colstrip and NorthWestern, the utility must contemplate a much bigger shift, from fossil fuels to something completely different. As explained in detail in NorthWestern's comments on the National Emission Standards for Hazardous Air Pollutants ("NESHAP") for the Coal- and Oil-fired Electric Utility Steam Electric Generating Units ("EGUs"), commonly known as the Mercury and Air Toxics Standards ("MATS Rule Update"), renewables and hydropower are key components of NorthWestern's energy mix, but they are either poor (renewables) or unavailable (e.g., significant additional hydropower capacity is not an option) substitutes for Colstrip's capacity. This makes the Proposed Rule an even more transformative and problematic assertion of regulatory power than the Clean Power Plan. Consequently, the rationale for applying the Major Questions Doctrine to the Proposed Rule is as compelling as it was for applying it to the Clean Power Plan.

Where it applies, the Major Questions Doctrine is a form of heightened scrutiny of administrative action, focused on the agency's assertion of authority. It is perhaps not as exacting as strict scrutiny, but it is far more demanding than rational basis review, and it is not deferential. Indeed rather than deference, the touchstone of review under the Major Questions Doctrine is "skepticism."[15]

The scope of an agency's statutory authority is evaluated not only on the basis of entire sections, but also each statutory term or phrase.[16] A significant body of case law exists, developed primarily in the 1970s and 80s, construing the various terms used in Section 111. In particular, these cases interpreted:

- Standards for determining whether a technology is "adequately demonstrated";[17]

[15] *Id.* at 2614.
[16] *Id.* at 2608 (discussing *Utility Air Regulatory Group v. EPA,* 573 U. S. 302, 324, 134 S. Ct. 2427 (2014)).
[17] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *see also Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 785 (D.C. Circ. 1976) (quoting same);

- The degree of confidence an agency must show to conclude that implementation of a technology is "achievable" under the timelines imposed by the Clean Air Act;[18]

- The allowable degree of future projection of technological development;[19] and

- What it means for a standard to be "uniform."[20]

These likely all remain good law, but must now be further interpreted in light of *West Virginia* and the Major Questions Doctrine. Because the Proposed Rule will be subject to scrutiny under the Doctrine, a reviewing court will likely demand that EPA's showing on each of these factors must be especially convincing. In other words, Congress has delegated to EPA the authority to determine what pollution control technology is the BSER, but courts will likely take a hard look at sweeping, poorly supported claims that CCUS has been adequately demonstrated, is reasonably achievable now at reasonable cost, and can be uniformly applied. This is especially true given the reversal of technical position that EPA has taken between the Clean Power Plan and the Proposed Rule, and the Congress' very recent and extensive legislation on the subject of climate change and technology development in the IRA.

As discussed below in the context of Colstrip, the Proposed Rule would fail the scrutiny traditionally applied under pre-*West Virginia* precedent, and cannot possibly survive review under the Major Questions Doctrine.

5. <u>Interaction between the Proposed Rule and Proposed MATS Rule Update</u>

On June 23, 2023, NorthWestern submitted comments on the proposed changes to the MATS Rule Update. A copy of those comments is attached as Exhibit C (split into seven parts due to file size). These comments are highly relevant to the Proposed Rule, in that, in addition to the difficulties and expense of complying with MATS Rule Update, they provide detailed information on:

- The role of Colstrip in providing reliable electrical service to Montana;

Sierra Club v. Costle, 657 F.2d 298, 330 (D.C. Cir. 1981); *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 952 (D.C. Cir. 2021).

[18] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999).

[19] *Portland Cement Ass'n v. Ruckelshaus*, 486 F. 2d 375, 391-392 (D.C. Cir. 1973).

[20] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431-33, n.46 (D.C. Cir. 1980).

- The lack of readily available generation alternatives;

- The inability to replace Colstrip's capacity by importing electricity in to Montana;

- The severe grid reliability and service risks that would occur if Colstrip's capacity is removed; and,

- NorthWestern's analysis of Colstrip closure scenarios.

NorthWestern also periodically references the MATS Rule Update comments in these comments.

6. ***Colstrip exemplifies why CCUS cannot be considered a Best System of Emissions Reduction for existing coal-fired EGUs under applicable law***

In their comments, EEI and Otter Tail make compelling cases why CCUS is not sufficiently developed at a national scale to be declared a BSER under Section 111. The Colstrip example helps illustrate the accuracy of their arguments. Specific facts related to Colstrip show that EPA has (a) substantially underestimated the costs of implementing CCUS; (b) overstated the presently achievable CO_2 capture rate; (c) understated implementation times for any subcategory in which new natural gas supply is involved; and (d) substantially understated implementation times for on-site capture equipment and related pipelines and equipment necessary to transport and sequester CO_2.

(a). CCUS would be cost-prohibitive at Colstrip

In 2018, the Department of Energy ("DOE") engaged in a detailed analysis of CCUS implementation at Colstrip. Importantly, DOE also considered available tax incentives and revenue streams. Regarding economics, DOE found the following:

> The study also assessed the economics of integrating a CO2 capture system, whereby the CO2 could be used for enhanced oil recovery (EOR). The recent expansion of 45Q CO2 tax credits (signed into law in February 2018) applied to EOR offers additional financial revenue to offset some of the capital and operational costs for the carbon capture, compression and transportation facilities. Capturing and compressing 63% of CO2 emissions from each unit (4.3 million metric tonnes per year per unit) using steam and power from the coal power plant (instead of providing them through a separate gas-fired combined heat and power plant) could cost around \$1,335 million, along with an annual operating cost of around \$108 million. The techno-economic assessment of CO2 capture for CO2-EOR found that

due to significant capital, operating and infrastructure costs, this option may not be financially attractive.

Exhibit D. EPA may respond that there have been substantial technological developments and additional incentives that have occurred since 2018; however, these have not been anywhere near so dramatic as to render the costs reasonable when working from a $1.335 billion capital, and $108 million annual operational, cost starting point. Moreover, the DOE cost estimates are far short of the actual costs of complying with the Proposed Rule, because DOE assumed a 63% CO_2 capture rate, well below the 90%-increasing-to-96% rates required under the Proposed Rule. Since each performance increment is progressively more difficult and costlier to achieve, improving from 63% recovery to 90% recovery would add hundreds of millions of dollars in capital and operational costs, if such an improvement were even possible. In addition, none of this accounts for significant inflation in material and labor costs since 2018. Therefore, even with improvements in technology and financial incentives since 2018, the DOE estimate is a substantial *underestimate* of the true costs of complying with the Proposed Rule.

DOE is at least as credible and authoritative as any of the sources relied upon by EPA. And because DOE considered the *entire* system of CCUS as potentially implemented at Colstrip, rather than generic individual and isolated component parts as calculated by EPA and its sources, the DOE estimate is *more* reliable and accurate than EPA's, even considering the passage of time.

(b). <u>EPA's estimated CO_2 capture rate is unrealistic</u>

As noted, DOE's analysis of retrofitting Colstrip assumed a CO_2 capture rate of 63%. Separately from the *cost* implications of improving rates from 63% to 90% or higher, DOE was charged with analyzing the feasibility and costs of achieving as reasonably high rates of capture as possible. The fact that DOE was only confident in estimating a 63% capture rate speaks volumes about the unrealism in EPA's estimates.

EEI observes that the existing coal CCUS capture systems at the Boundary Dam and Petra Nova facilities have target availability rates in the 70% range, and have struggled to achieve even that over any sustained period. If DOE estimates a capture rate of 63% for CCUS at Colstrip, this reinforces, from an agency with relevant experience, that it is EPA and the Proposed Rule that is the outlier. Effective capture rates in the 60-70% range would have major implications for compliance with the Final Rule, the cost-effectiveness of CCUS at Colstrip (and elsewhere), and the environmental benefits of the Proposed Rule. The latter is discussed more fully in Section 7.

(c). New natural gas supply cannot be provided, or provided cost-effectively, to Colstrip within the deadlines in the Proposed Rule

Natural gas would be an important component of compliance with the Proposed Rule in at least two scenarios. First, NorthWestern could theoretically comply with the Proposed Rule under the Medium term Subcategory by making an enforceable closure commitment for Colstrip for no later than January 1, 2040, *and* installing co-fired natural gas to supplant at least 40% of Colstrip's capacity by January 1, 2030. Second, NorthWestern could elect to replace the entirety of Colstrip's capacity with natural gas, in the same location or at a new site. This approach could bring the Near term Subcategory into play, but would again require the replacement natural gas supply to be operational by January 1, 2030, because Colstrip could only operate at 20% capacity after that date. Colstrip presently operates at over 70% capacity. Consequently, from the perspective of natural gas as a compliance mechanism, the Medium term and Near term Subcategories are essentially equivalent.

These options are infeasible on both timing and cost grounds. NorthWestern has previously examined natural gas replacement for Colstrip's capacity as part of its Integrated Resource Planning process. Supplying Colstrip with sufficient natural gas to replace even 40% of Colstrip's capacity would require a new pipeline, most likely tapping into existing pipelines in eastern Montana. Preliminary assessment indicated such a pipeline would require substantial enhancement of existing compression facilities on existing lines, and then the new pipeline would need to traverse approximately 200 miles over new pipeline right-of-way. Under Montana pipeline siting regulations, such an exercise would likely require at least a decade, and there is a strong likelihood of further delays by litigation. There is no scenario under which a new pipeline of this magnitude could move from design to operational status in the less than seven years remaining until January 1, 2030.

In addition, these scenarios are even less plausible once costs are considered. Even if it could be constructed within the deadlines of the Proposed Rule, a new pipeline to supply Colstrip with natural gas would cost in excess of a billion dollars to construct. For example, using EPA's estimated costs per inch-mile of pipeline, Otter Tail explains that new, average diameter pipelines would cost over $5 million per mile, translating to hundreds of millions in costs to supply the Big Stone or Coyote Station facilities. Installing a new pipeline to Colstrip would be vastly more expensive, owing to the greater distance, more challenging intervening terrain, and the extent of new pipeline right-of-way required. All told, the cost of a new natural gas line to Colstrip would substantially exceed $1 billion. This is cost-prohibitive on its face.

Under the co-firing Medium term Subcategory, the new pipeline would then only have at most ten years of useful life. Operations could theoretically extend longer under the Near term Subcategory, but it is highly unlikely that Colstrip would be operated very long at the maximum 20% capacity allowed by the Near term Subcategory. As Talen explains, Colstrip is ill-suited to function in a peaking capacity, and Colstrip's full capacity is presently needed to maintain sufficienta and reliable electrical capacity. This again renders the option not cost-effective.

(d). EPA's CCUS implementation timelines are unrealistic

(i). Design, permitting, construction and commissioning of CCUS at Colstrip is not possible within the timeframes in the Proposed Rule

Even if NorthWestern began attempting to install CCUS at Colstrip *today*, before the Proposed Rule is even finalized, it could not meet the deadlines in the Proposed Rule. A CCUS system for a facility like Colstrip would require extensive design work, consuming approximately two years at a minimum.[21] Bids, permitting, construction and commissioning would follow. CCUS at Colstrip would require numerous state approvals, including from the Montana Public Service Commission and the Montana Department of Environmental Quality. NorthWestern has recent experience in this regard, involving the Yellowstone County Generating Station ("YCGS"), a 175MW natural gas fueled facility. Construction of YCGS has been a much less complex, expensive and time-consuming process than potentially designing and installing a complete CCUS system at Colstrip. The RFP process related to YCGS was initiated in January 2020, and the project is currently forecast to become operational by the end of the third quarter in 2024. Importantly, NorthWestern has a critical need for the YCGS to add flexibility and capacity to its portfolio, and has been driving the project forward as quickly as possible, consistent with responsible and lawful implementation.

With this recent experience, NorthWestern's familiarity with state regulatory requirements, and assuming similarly aggressive scheduling, NorthWestern estimates that design, permitting, construction and commissioning of a CCUS system at Colstrip would likely take at least three times as long as YCGS. This would take NorthWestern well past the Proposed Rule's compliance deadlines.

[21] In 2021, NorthWestern and Talen received a CCUS feasibility assessment proposal from a contractor that estimated a 20 month design phase, not including sequestration or use of the captured carbon. NorthWestern and Talen did not pursue the proposal further because the overall project costs and obstacles did not appear to have materially changed from the 2018 DOE assessment.

(ii). A CO2 pipeline servicing Colstrip cannot become operational in the timeframes assumed in the Proposed Rule

As explained in EEI's comments, EPA's timeline assumptions regarding CO_2 pipeline permitting, construction, and operation are wildly unrealistic. This is further demonstrated by recent experience in Montana. Montana is in some ways among the more favorable environments for implementing a CO_2 pipeline, in that it has well-characterized geology for storage and use for CO_2 for Enhanced Oil Recovery ("EOR") in eastern Montana and western North Dakota. Indeed, these conditions led to the construction of the Cedar Creek Anticline CO_2 pipeline project by Denbury, LLC ("CCA Pipeline").

The CCA Pipeline required at least a decade to develop. Denbury publicly described plans to sequester CO_2 in the Cedar Creek Anticline in July 2011.[22] In 2015, Denbury described the CCA Pipeline in greater detail to the North Dakota Interim Committee on Taxation.[23] Federal environmental review for the CCA Pipeline commenced in September 2017.[24] In October 2018, Denbury announced that construction was poised to begin, and the first CO_2 was injected in early 2022.[25] The CCA Pipeline is not yet fully operational.

The CCA Pipeline enjoyed many advantages that would not be applicable to a Colstrip CCUS pipeline. First, the CCA Pipeline is supplied by industrial generators who are otherwise free to emit CO_2 directly to the atmosphere. Consequently, the CCA Pipeline could be designed and optimized for Denbury's needs and the EOR site, without concern for constraining the suppliers' operations. In contrast, a Colstrip CCUS pipeline would need to be designed to transport essentially all of Colstrip's CO_2 generation, reliably and at risk of enforcement under the Clean Air Act. Similarly, design, permitting, and construction timing was all at Denbury's option, whereas NorthWestern and any CCUS pipeline contractor would be racing against the deadlines imposed by the Proposed Rule. Third, Denbury was able to construct the CCA Pipeline almost entirely along existing right-of-way. Such an option would not exist for a Colstrip CCUS pipeline, and new pipeline right-of-way is materially more difficult and takes longer to secure than leveraging existing right-of-ways. Fourth, and perhaps most importantly, a Colstrip CCUS pipeline would likely face opposition and litigation that Denbury did not experience. A Colstrip CCUS pipeline would be viewed (correctly) by many in the environmental community as a Colstrip life-extender. They will view this outcome as far

---

[22] Denbury Launches $400M EOR Project in Cedar Creek Anticline - Natural Gas Intelligence.

[23] Denbury Presentation Template (ndlegis.gov).

[24] EplanningUi (blm.gov).

[25] Cedar Creek Anticline CO2 Pipeline creates new net-carbon negative oil production and carbon storage opportunities for Montana - Issuu.

inferior to closing the facility, exposing NorthWestern to opposition, procedural delays, and extensive litigation.

Importantly, the CCA pipeline may also foreclose sequestration opportunities for Colstrip CO_2 that might have otherwise existed. It is not at all clear that the region being serviced by the CCA pipeline could absorb an infusion of additional CO_2 for EOR or other purposes on top of the CCA deliveries. Consequently, while EPA might point to the CCA pipeline as a proof of concept for Coltrip CO_2 sequestration, the reality is that it may prove just the opposite.

Given these considerations, it is not realistic to conclude that a CCUS pipeline servicing Colstrip could become operational in less than a decade. Importantly, effective CCUS utilization is entirely dependent on the lengthiest component of the CCUS system. If implementing CCUS at Colstrip somehow goes faster than anticipated, it does no good until the CCUS pipeline is operational, and vice versa. This compounds the number of scenarios where EPA's timelines would be simply unattainable for NorthWestern, regardless of the cost.

7. ***The Proposed Rule poses substantial risks of adverse environmental and human welfare outcomes***

All other things equal, Colstrip is nearing the end of its useful life. NorthWestern presently does not expect Colstrip's RULOF to extend beyond 2042. NorthWestern has also closely examined Colstrip closure scenarios as part of its 2023 IRP process, analyzing scenarios involving closures in 2025, 2030, and 2035. The 2025 and 2030 closure scenarios resulted in materially higher total energy supply costs, amounting to \$1.1 billion in higher costs (25% increase over the base case) for a 2025 closure, and \$540 million higher costs (12.1% increase over the base case) for a 2035 closure. *See* figure 8-16 in the 2023 IRP which is included as Exhibit B-1 to NorthWestern's MATS Rule Update Comments, attached here as Exhibit C_Part2 (closing Colstrip in 2025 is included in the scenario labeled "Environmental"). Moreover, these scenarios rely on substantial purchases of power at market rates, in excess of \$50 million each year commencing with Colstrip's closure. *Id.* As explained in NorthWestern's comments on the MATS Rule Update, there is substantial uncertainty whether such large market purchases can even be consistently executed and delivered, especially during peak load events. Consequently, the 2025 and 2030 closure scenarios are accompanied by worrisome grid stability and service interruption hazards.

As also discussed in detail in the MATS Rule Update comments, NorthWestern has statutory obligations to serve its customers that require NorthWestern to provide reliable service, and there are no good options for replacing Colstrip's capacity before the mid-2030s, while maintaining reliable service. NorthWestern is thus left in the unenviable position where it may not be able to lawfully close, or even significantly reduce usage of, Colstrip before 2035.

Notwithstanding the exorbitant costs of doing so, these facts could compel NorthWestern to implement CCUS at Colstrip and materially extend Colstrip's RULOF, rather than closing Colstrip in the early 2040s. In this scenario, the Proposed Rule would materially extend Colstrip's RULOF, because NorthWestern could not plausibly invest the billions needed to implement CCUS at the facility, only to close it in 2042 as currently planned.

A perverse environmental equation would then commence in 2042. As EEI asks, what if EPA is wrong? In this specific context, what if EPA is wrong about effective capture rates, and the attainable net capture rate is more like 60%-70% achieved at existing facilities[26] rather than the forecast 90% that has not been consistently achieved anywhere? EPA would not have the legal authority or ability to forcefully shut Colstrip down, because there are countervailing state and federal reliability mandates that cannot be achieved without Colstrip, and the opportunity to thoughtfully replace Colstrip would have been lost.

Additionally, CCUS has a parasitic load of between 20-30% of a facility's rated capacity. Colstrip is already operating at high capacity, meaning that this parasitic load cannot be satisfied by simply operating Colstrip more intensively. This further means that the additional capacity to cover the capacity lost to the operation of a CCUS system must be generated, consistently and reliably, from other sources. In Section 6.c., NorthWestern has already explained that supplying natural gas to Colstrip is infeasible and cost-prohibitive within the timelines of the Proposed Rule. Consequently, hundreds of megawatts would need to be diverted from NorthWestern's existing capacity-constrained generation portfolio. This both deprives NorthWestern of revenue and reduces system reliability. In particular, Colstrip's capacity is most needed when carbon-free generation is reduced or unavailable.[27] It is unclear that imported capacity from other NorthWestern or external sources would even be available under such conditions. And even if it is, the capacity would come primarily from fossil fuel sources.[28] If the effective capture rate for a Colstrip CCUS system is 60-70%, it would only take a few additional years of Colstrip operations beyond 2042 to completely erase any carbon savings that were realized between CCUS installation and 2042. Such a result would be environmental and policy insanity, but is all too likely based on the current state of CCUS technology.

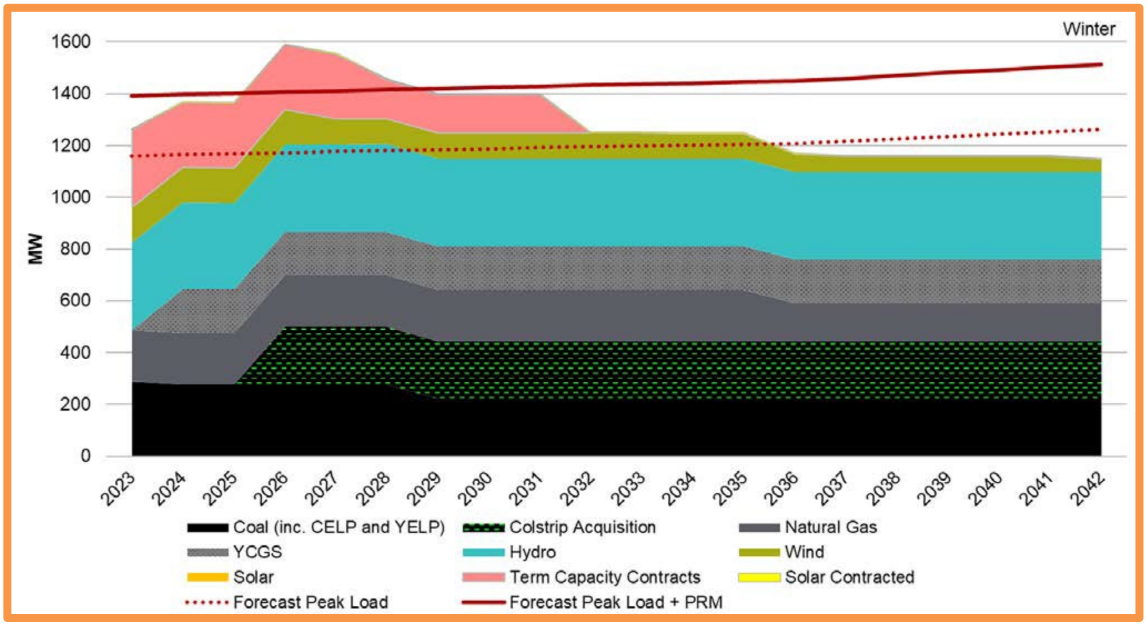
---

[26] "Attainable net capture rate" includes more than the percentage captured from the flue stream routed through the capture system; it also includes system down time (during which the capture rate is zero) and any flue gas that is not routed through the system. All CCUS systems deployed to date have experienced significant downtimes, and/or have not processed all flue gas.

[27] *See* Exhibit C_Part1 (NorthWestern's MATS Rule Update Comments §§ 4 and 5).

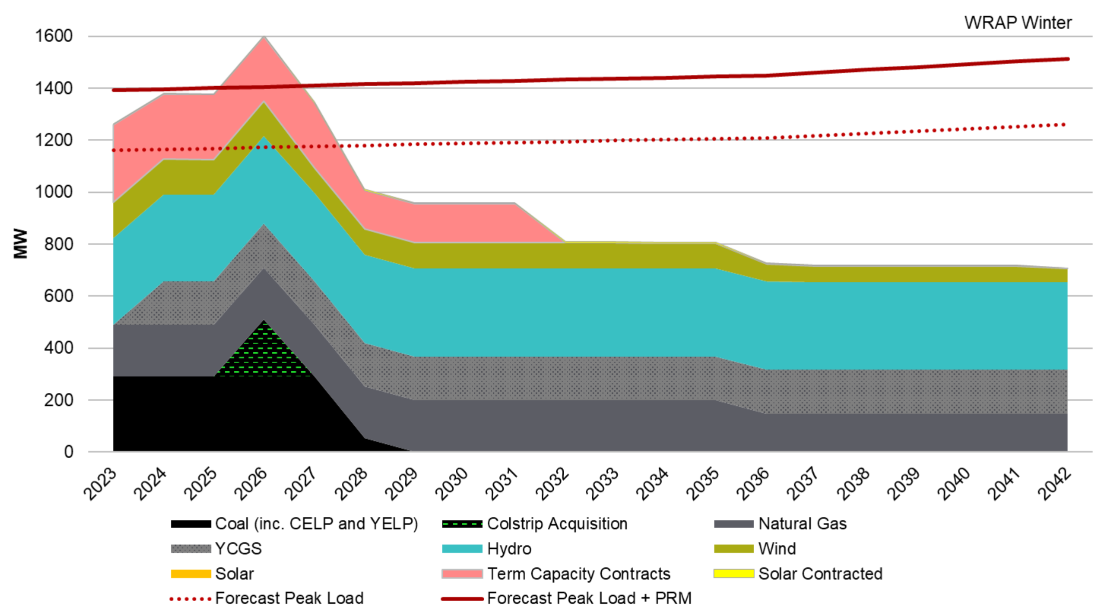
[28] *Id.*

NorthWestern's Colstrip conundrum is illustrated in the following charts. First, NorthWestern faces future capacity deficits even with Colstrip generation, and will be working diligently to add capacity to fill that gap:



If CCUS could somehow be installed at Colstrip within the timelines of the Proposed Rule (which, as explained is infeasible), the parasitic load of a CCUS system would negate 20-30% of Colstrip's net capacity, and exacerbate the system capacity gap.

Second, if Colstrip is closed early, NorthWestern's system would plunge into an immediate, severe, and potentially life-threatening capacity deficit:



The Proposed Rule, if finalized, would thus place NorthWestern in an untenable position – it cannot afford to continue operating Colstrip, and it cannot afford not to. Colstrip thus presents a concrete example why EPA must reconsider the Proposed Rule.

8. Many of the statutory financial incentives may not be available

EPA has downplayed the exorbitant costs of the Proposed Rule by noting the extensive tax incentives available to energy transition investments under the IRA and other laws. NorthWestern fully supports these incentives, but there is a disconnect between the timelines and criteria for qualifying for the incentives, as compared with the realities of bringing CCUS into operation. First, the construction deadline for eligibility is January 1, 2033. As explained in Sections 6 and 7, there is no reasonable prospect that a qualifying integrated system – including the on-site CCUS capture equipment and a CO_2 sequestration pipeline or other usage – could be designed, financed, permitted, constructed, and put into operation for Colstrip on that timeframe. Equally importantly, NorthWestern would need to invest the billions of dollars up front *in the hope* that all aspects of the effort would come together in time. It is highly unlikely that NorthWestern could obtain financing for such a speculative venture or the Montana Public Service Commission would approve rate recovery for expenditures on those terms.

Second, the IRA specifies that to qualify for the 45Q tax credits, the capture equipment must be "designed" to capture at least 75% of the baseline CO_2 emissions of the facility. No EGU in existence has achieved net CO_2 capture rates that high over a sustained period. As discussed in Section 6.a., a more reasonably achievable capture rate as estimated by DOE would be in the range of 60-70%. It is highly unlikely that any reputable design/engineering firm (or collection of firms) will be prepared to give a 75% capture rate design certification guarantee for a Colstrip CCUS system that NorthWestern could reasonably rely on, given the timelines involved, the complexity of the systems, the lack of proven existing facilities, supply chain and labor constraints, and a myriad of other practical challenges to such a project.

The YCGS again provides a vivid example of these uncertainties and factors in play. As discussed, the YCGS employs very well established reciprocating engine technology, and is a far smaller and less complex system than CCUS at Colstrip would be. Yet for a variety of reasons, some outside of the contractor's or NorthWestern's control, the YCGS has not been able to be constructed on time and on budget. Opportunistically, the principal contractor for YCGS has declared force majeure, and is seeking to extricate itself from a number of its contract guarantees. Whether that will be successful is yet to be determined.

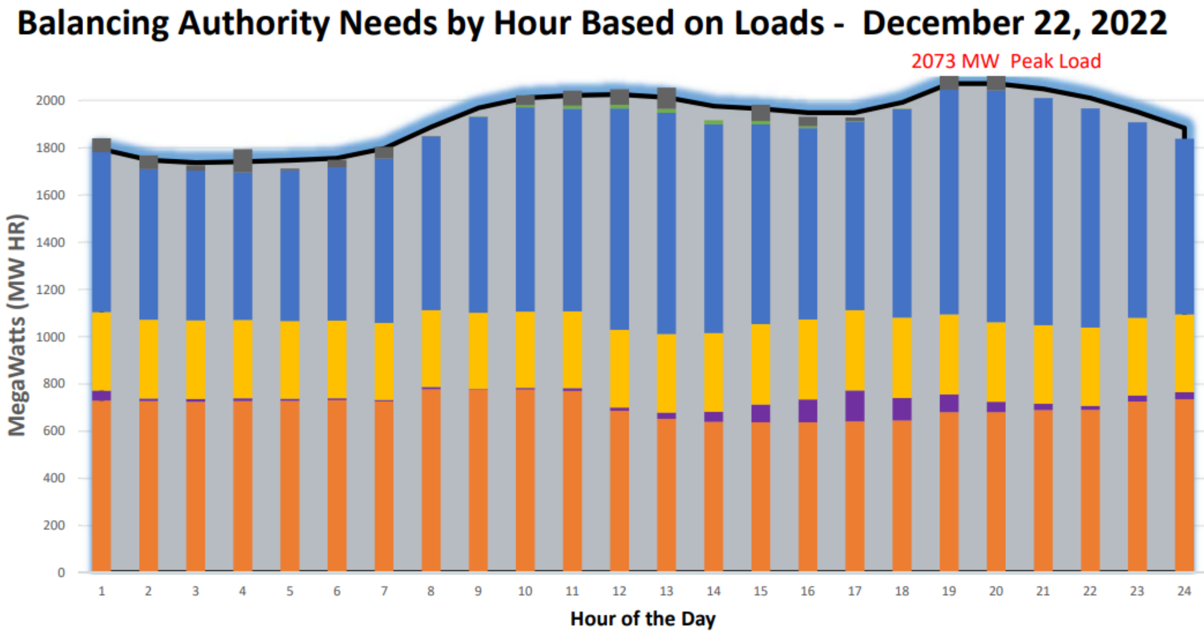
The stakes for Colstrip would be an order of magnitude higher than for the YCGS. To the extent that a contractor would be prepared to provide a 75% design rate guarantee, the guarantee would likely be so extensively qualified and hedged that the IRS may conclude that it does not meet the statutory requirements. Moreover, based on information presently available, if Colstrip does not achieve a 75% capture rate, the IRS might conclude that no contractor could reasonably have offered such a guarantee, and NorthWestern could not reasonably have relied upon, a 75% capture rate guarantee. It is not lost on NorthWestern, and should be acknowledged by EPA, that future IRS determinations on qualifying investments may not be made by an Administration and IRS with the same priorities and policies as the current Administration. And because the IRA is so new, there is very little interpretive case law on the 45Q provisions to give either the IRS or utilities greater confidence in how the statute will be interpreted. For these reasons, NorthWestern simply cannot rely on the 45Q incentives as a basis for defraying the costs of CCUS at Colstrip.

This is another consequence of EPA force-feeding a developing technology. As discussed, CCUS for coal-fired EGUs cannot be considered BSER, because the technology has not been shown to be adequately demonstrated or achievable. And because the technology has not been adequately demonstrated or achievable, the financial incentives that are nominally available to help defray the costs of the technology are also too uncertain for any responsible investor-owned and regulated public utility to rely on. Consequently, EPA cannot reasonably contend that currently available public subsidies and incentives for CCUS render the technology cost-effective.

9. <u>Grid management by importation and emergency order and is not an acceptable state of affairs</u>

EPA's Integrated Planning Model recognizes the looming Montana capacity deficit, but assumes this will be ameliorated by importation from renewable generation build-out in surrounding states. This is a flawed and dangerous assumption. As detailed in NorthWestern's MATS Update Comments, transmission lines into Montana are already highly congested and inadequate, and adding transmission capacity has proven extremely difficult and time-consuming. It is not plausible to materially increase interstate transmission capacity within the timeframes of the Proposed Rule. Indeed, this was one of the primary reasons for constructing the YCGS – to make NorthWestern less dependent on importation of power *even with* Colstrip operating through 2042.

In addition, as also explained in the MATS Update Comments, renewables are vulnerable to regionally-synchronized capacity shortfalls due to atmospheric conditions. A vivid example of this occurred in late 2022. Cold weather and calm conditions reduced renewable generation and drove up the need for electricity and its price. For hours at a time, Montana's existing portfolio, including maximum utilization of Colstrip, could supply only *half* the electricity needs of the NorthWestern system:



NorthWestern was barely able to make it through that period without service disruptions. Significant reductions in renewable generation in the region throughout that same period required heavy reliance on existing fossil fuel sources at punishing market rates. These scenarios will only get more frequent and severe as fossil fuel facilities in the region continue to close, even in the absence of the Proposed Rule. The Proposed Rule will make things worse.

EPA may be tempted to conclude that Department of Energy Emergency Orders under the Federal Power Act provide a "safety valve," allowing for selected relaxation of environmental controls while reaping the benefit of such controls at all other times. This is an illusion. As Otter Tail explains, the frequency of such orders is already increasing. And, the availability of DOE emergency order authority is unavailing if the underlying capacity does not exist or is already fully utilized. The Proposed Rule therefore puts the region on a path to a capacity and reliability crisis. NorthWestern urges EPA to slow down and more fully coordinate with DOE, FERC, and regional reliability organizations to develop a revised plan that advances the Administration's goals on a more realistic timetable.

10. __Requests__

As a result of the foregoing legal, factual, and policy issues in the Proposed Rule, NorthWestern respectfully requests the following actions.

(a). EPA should withdraw the Proposed Rule until technological developments occur that can sustain national CCUS implementation

As explained above and by other commenters, the Proposed Rule is unlawful under existing precedent, and certainly if the Proposed Rule is subjected to scrutiny under the Major Questions Doctrine. As a result, and because of the significant prejudice and injury NorthWestern and nearly all Montanans will suffer, EPA should withdraw the Proposed Rule until such time as CCUS technology has advanced to a stage where it can be implemented nationally in compliance with Section 111(d).

(b). If rulemaking proceeds, EPA should materially extend the compliance deadlines and lower the required carbon capture rate

In the event the Proposed Rule is finalized, at a minimum, the compliance deadlines should be substantially extended to comport with the state of technology, the complex, interacting systems that need to be designed and implemented together, and the realities of design, permitting, construction and commissioning. A realistic deadline to install CCUS and achieve a capture rate of approximately 65% would be the early 2040s.

(c). If rulemaking proceeds, EPA should also create an opt-out option for facilities that decide, within one year of the publication of the Final Rule, to enforceably commit to closure by December 31, 2035.

Any Final Rule should revise the current Imminent term retirement subcategory, allowing units to enforceably commit to a retirement date of no later than December 31, 2035 (and where continued operation after 2035 would later be permitted if (i) the unit is essential to maintain regional grid reliability, as determined by the Western Regional Adequacy Program, Regional Transmission Organizations, Independent System Operators, North American Electric Reliability Corporation, or other similar system reliability authorities; or (ii) or if EPA determines that additional time is required to allow the unit to transition to renewable or clean energy generation).

This revision is warranted for several reasons. First, the four year extension is far more realistic given the lead times associated with planning long-term electric generation transitions, the need to finalize the Proposed Rule, and the developing nature of CCUS. Second, such a revision would materially reduce the likelihood of perverse outcomes from utilities rushing to install undeveloped, costly technology, and thereby extending the life and emissions of facilities that otherwise would have closed. Third, the express recognition of reliability needs and thoughtful transition to renewables would both promote Administration policies and acknowledge the critical role that other agencies with relevant expertise to grid reliability play in this sector of national significance.

Conclusion

NorthWestern is disappointed the Proposed Rule, in its current form, is unrealistic regarding its intended objectives, and poses substantial environmental and human welfare risks. Nevertheless, NorthWestern's strong carbon-free portfolio performance and Net Zero 2050 commitments demonstrate that it shares many of the Administration's long term environmental objectives. NorthWestern is available to further discuss the consequences of the Proposed Rule and potential solutions to the problems it poses. If you have any questions regarding these comments, or would like to further engage on the subject, please contact me at 406-443-8903 or shannon.heim@northwestern.com.

Sincerely,

Shannon M. Heim

Shannon M. Heim
Vice President and General Counsel
NorthWestern Energy

APPENDIX E

SELECT STAY MOTION PAPERS FILED IN THE D.C. CIRCUIT CASE

ORAL ARGUMENT NOT YET SCHEDULED

Nos. 24-1190 and 24-1217 (consolidated with No. 24-1119)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

TALEN MONTANA, LLC,
Petitioner,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY and
MICHAEL S. REGAN, Administrator, U.S. Environmental Protection Agency,
Respondents.

NORTHWESTERN CORPORATION,
Petitioner,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY and MICHAEL S. REGAN, Administrator, U.S. Environmental Protection Agency,
Respondents.

On Petitions for Review of a Final Action of the
U.S. Environmental Protection Agency

PETITIONER TALEN MONTANA, LLC AND PETITIONER NORTHWESTERN CORPORATION'S JOINT MOTION FOR STAY

(*Counsel listed on inside cover*)

Joshua B. Frank
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street N.W.
Washington, D.C. 20001
Tel.: (202) 639-7748
(202) 639-1130
joshua.frank@bakerbotts.com
joshua.lee@bakerbotts.com

Counsel for Petitioner
Talen Montana, LLC

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue N.W.,
Suite 900
Washington, D.C. 20005
Tel.: (202) 442-3555
magid.chip@dorsey.com

Michael Drysdale (*Of Counsel*)
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402
Tel.: (612) 340-5652
drysdale.michael@dorsey.com

Counsel for Petitioner
NorthWestern Corporation
d/b/a NorthWestern Energy

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

CASES

GLOSSARY

Andover Report	Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants* (Aug. 19, 2021), EPA-HQ-OAR-2018-0794-4583
CAA or the Act	Clean Air Act, 42 U.S.C. §§ 7401 to 7671q
EGU	Electric utility steam generating unit
EPA or Agency	U.S. Environmental Protection Agency
ESP	Electrostatic precipitator
Final Rule	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review: Final Rule, 89 Fed. Reg. 38508 (May 7, 2024)
GHG Rule	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: Final Rule, 89 Fed. Reg. 39798 (May 9, 2024)
fPM	Filterable particulate matter
GHG	Greenhouse gas
HAP	Hazardous air pollutant
MATS Rule	National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and

	Small Industrial-Commercial-Institutional Steam Generating Units: Final Rule, 77 Fed. Reg. 9304 (Feb. 16, 2012)
Proposed Rule	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review: Proposed Rule, 88 Fed. Reg. 24854 (Apr. 24, 2023)
RTC	EPA, Response to Comments (Apr. 2024), EPA-HQ-OAR-2018-0794-6922
RTR	Risk and Technology Review
WRAP	Western Regional Adequacy Program

LIST OF ATTACHMENTS

Exhibit 1	Declaration of Dale E. Lebsack, Jr., President of Talen Montana, LLC and Chief Fossil Officer for Talen Energy Corporation
Exhibit 2	Declaration of John D. Hines, Vice President, Supply, Environment, and Montana Government Affairs, of NorthWestern Corporation d/b/a NorthWestern Energy
Exhibit 3	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review: Proposed Rule, 88 Fed. Reg. 24854 (Apr. 24, 2023)
Exhibit 4	Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants* (Aug. 19, 2021), EPA-HQ-OAR-2018-0794-4583
Exhibit 5	NorthWestern Comments (June 23, 2023), EPA-HQ-OAR-2018-0794-5980
Exhibit 6	Talen Montana Comments (June 23, 2023), EPA-HQ-OAR-2018-0794-5987
Exhibit 7	EPA, Response to Comments (Apr. 2024), EPA-HQ-OAR-2018-0794-6922
Exhibit 8	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review: Final Rule, 89 Fed. Reg. 38508 (May 7, 2024)

INTRODUCTION

Talen Montana, LLC ("Talen Montana") and NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern") (collectively "Petitioners") respectfully request a stay of the U.S. Environmental Protection Agency's ("EPA" or "Agency") recently revised Mercury and Air Toxics Standards rule, 89 Fed. Reg. 38508 (May 7, 2024) ("Final Rule").

By EPA's own account, the Final Rule targets the Colstrip Power Plant ("Colstrip"). The Administrator himself spoke candidly about EPA's wishes to make coal-fired power plants "not worth investing in," forcing "an expedited retirement."[1] He later testified that Colstrip must be further regulated because it is "cheating the system,"[2] even though Colstrip meets all currently applicable emissions standards. The Final Rule imposes almost half of its regulatory burden on Colstrip alone. According to EPA, Colstrip is the only facility required to install completely new pollution control equipment to meet the Final Rule, at an estimated capital cost of over $350M.

---

[1] Lisa Friedman, *E.P.A. Describes How It Will Regulate Power Plants After Supreme Court Setback*, N.Y. Times (July 7, 2022), https://www.nytimes.com/2022/07/07/climate/epa-greenhouse-gas-power-plant-regulations.html.

[2] *FY 2025 Request for EPA: Hearing Before the H. Comm. on Appropriations*, at 31:59, 118th Cong. (Apr. 30, 2024) (testimony of Hon. Michael S. Regan), https://appropriations.house.gov/events/hearings/budget-hearing-fiscal-year-2025-request-environmental-protection-agency.

The Final Rule fails to account for the impacts that EPA's contemporaneous rule regulating greenhouse gas ("GHG") emissions from coal-fired power plants will have on Colstrip. 89 Fed. Reg. 39798 (May 9, 2024) ("GHG Rule"). If not struck down, the GHG Rule forces Colstrip to retire before 2032, leaving at most four years for Colstrip to recoup the costs of compliance with the Final Rule, and exacerbating the Final Rule's impacts. That compressed timeline risks Colstrip retiring even sooner (i.e., 2027, the Final Rule's compliance deadline) to avoid non-economic compliance costs, with concomitant severe economic and reliability disruptions.

EPA knew all this. In comments, Petitioners asked EPA to consider the collective and interlocking impacts of the GHG Rule and the Final Rule. Petitioners asked EPA to offer a retirement subcategory that would allow Colstrip to make an orderly retirement, on the same timelines afforded by the GHG Rule. And Petitioners asked EPA to consider the grid reliability consequences of early retirement, and the extreme costs and low cost-effectiveness of required controls required for Colstrip. Despite the Final Rule's focus on Colstrip, EPA failed to address comments specific to Colstrip.

For EPA to target Colstrip and then disregard the Final Rule's impacts on Colstrip is the pinnacle of "fail[ing] to consider an important aspect of the problem." *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Absent a stay, a decision by this Court overturning EPA's illegal actions will come after Colstrip's owners have either irrevocably decided to prematurely retire the plant or install unnecessary controls. Immediate relief is essential to avoid irreparable harm to Petitioner's operations, employees, and the communities that rely on the plant for economic stability and reliable power.

BACKGROUND

I. Statutory Framework

Section 112 of the Clean Air Act ("CAA" or "Act") governs hazardous air pollutants ("HAPs"). 42 U.S.C. § 7412. Electric utility steam generating units ("EGUs") such as coal-fired power plants are regulated under this Section if EPA finds it "appropriate and necessary." *Id.* § 7412(n)(1)(A).

Following such a finding, EPA must set HAP emission standards for EGUs. Such standards require "the maximum degree" of emission reductions EPA, considering "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable." *Id.* § 7412(d)(1), (2).

At least every eight years, EPA "shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies)" the emission standards. *Id.* § 7412(d)(6). Additionally, within eight years after promulgation, EPA must conduct a one-time assessment of the residual risk remaining. If the residual risk is unacceptable, the Agency must revise the standard to "provide an ample margin of safety to protect public health." *Id.* § 7412(f)(2). EPA has typically combined the first set of eight-year reviews, commonly referred to as a "Risk and Technology Review" ("RTR").

II. Rulemaking and Procedural History

EPA initially determined that it was "appropriate and necessary" to regulate HAP emissions from EGUs, 65 Fed. Reg. 79825 (Dec. 20, 2000), issuing standards in 2012. 77 Fed. Reg. 9303 (Feb. 16, 2012) ("MATS Rule").

In 2020, EPA conducted the first RTR of the MATS Rule, finding that the residual risks were acceptable and there was no cost-effective control technology that would further reduce emissions. EPA also changed its position and found it was not "appropriate and necessary" to regulate HAP emissions from EGUs. 85 Fed. Reg. 31286 (May 22, 2020).

In a new Administration, EPA again flipped. First, the Agency redetermined that it is appropriate and necessary to regulate EGUs under CAA Section 112. 88 Fed. Reg. 13956 (Mar. 6, 2023). Second, the Agency reviewed the 2020 RTR. EPA endorsed the RTR's finding that residual risks were low and acceptable. Nevertheless, EPA concluded that existing control technologies "are more widely used, more effective, and cheaper" and proposed to revise the MATS Rule to lower the filterable particulate matter ("fPM") emission limit. 88 Fed. Reg. 24854, 24866–72 (Apr. 24, 2023) ("Proposed Rule").

Meanwhile, EPA contemporaneously proposed to regulate GHG emissions from EGUs via the GHG Rule pursuant to CAA Section 111. If an EGU does not install carbon capture and sequestration or co-fire natural gas to comply with the emissions limits, the plant must cease operations before 2032. 89 Fed. Reg. at 39801, 40057.

EPA released both rules on the same day and finalized them two days apart. The Final Rule revised the fPM limit for existing EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. Plants must meet this limit by July 8, 2027, absent a potential one-year extension. 89 Fed. Reg. at 38518–19.

Talen Montana and NorthWestern filed their Petitions for Review of the Final Rule on June 10 and 24, 2024, respectively.[3] Petitioners requested EPA to stay the Final Rule pending judicial review. EPA has not acted on that request.

ARGUMENT

This Court should stay the Final Rule because (1) Petitioners will likely prevail on the merits, (2) Petitioners will be irreparably injured if the Court withholds the requested relief, (3) it is unlikely that other parties will be harmed if relief is not granted, and (4) the public interest favors a stay. D.C. Cir. R. 18(a)(1); *see also In re NTE Connecticut, LLC*, 26 F.4th 980, 987–88 (D.C. Cir. 2022).

---

[3] Petitioners are also part of an ad hoc coalition of electric generating companies that challenged the GHG Rule. The consolidated case is pending. *West Virginia v. EPA*, No. 24-1120 (D.C. Cir. filed May 9, 2024).

I. Petitioners are Likely to Prevail on the Merits.

A. The Final Rule Exceeds EPA's Statutory Authority.

"Section 112(d)(6) [of the CAA] requires EPA to 'review, and revise as necessary (taking into account ***developments*** in practices, processes, and control technologies)' the emissions standards promulgated under section 112." *Ass'n of Battery Recyclers, Inc. v. EPA*, 716 F.3d 667, 670 (D.C. Cir. 2013) (emphasis added) (quoting 42 U.S.C. § 7412(d)(6)). Such "developments" are the bare minimum for EPA to act under Section 112(d)(6). *See, e.g., Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 11 (D.C. Cir. 2015).

EPA did not meet that bare minimum. Despite multiple efforts and years of soliciting information on new/improved technologies that control HAP emissions, EPA could not identify any new control technology, practice, or process.

1. EPA Found No "Developments" in Technology.

EPA observed that many EGUs were using long-***existing*** control technologies (fabric filters and electrostatic precipitators ("ESPs")) that allowed them to report lower fPM emission rates. 89 Fed. Reg. at 38530. And because many EGUs reported fPM emissions below the current limit at lower costs, EPA found those to be "cognizable developments," a "clear trend in control efficiency, costs, and technological improvements." EPA, Response to Comments (Apr. 2024) ("RTC"), Ex. 7, at 11–12.

That EGUs are using existing technology—literally for decades—cannot amount to a "development" in technology. "Development" means "[t]he process or fact of developing; the concrete result of this process," such as the "[e]volution or bringing out from a latent or elementary condition." *development*, Oxford English Dictionary (2d ed. 1989). Broader, more cost-effective use of decades-old technologies is not an "evolution." This plain reading comports with how courts interpret Section 112(d)(6). *See NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008) (rejecting petitioners' call to revise emission standards under Section 112(d)(6) because petitioners "have not identified any post-1994 technological ***innovations*** that EPA has overlooked" (emphasis added)).

EPA references *Surface Finishing* to justify the Final Rule, *see, e.g.*, 89 Fed. Reg. at 38521. This fails for several reasons. First, the interpretation of "developments" was never in dispute; the petitioner never challenged it. 795 F.3d at 11 ("The Association does not directly challenge those interpretations . . . .").

Second, the Final Rule is much removed from the "technological improvements" that *Surface Finishing* found to be within the scope of "developments" (i.e., those "that could result in significant emission reductions"). Here, EPA could not identify any "improvements" that "resulted in emissions reductions."[4] *Cf. id.* Rather, EPA states that new "more durable materials" reduce wear-and-tear which, in turn, could "reduce the effectiveness" of the pollutant capture. Tellingly, at no point does EPA validate this claim or quantify the lowered emission figures from those new materials. *See* 89 Fed. Reg. at 38530.

Third, *Surface Finishing* had no bearing on whether "new information" can be considered "developments" or "improvements." The court's discussion of "intervening information" and "[n]ew data" was limited to why EPA's position change was justified. *See* 795 F.3d at 11–12. Here, EPA did not find "developments," and accordingly, cannot revise the emission standard.

2. EPA's Justification for the Final Rule Was Pretextual.

The real driver behind EPA's new emission standard was the Agency's observation that most EGUs were already using technology that reduced emissions. As explained above, this reality does not authorize a change. To sidestep this conundrum, EPA referenced a single report published in 2021 for an environmental non-profit, to be referred herein as the "Andover Report," Ex. 4. *See* 89 Fed. Reg. at 38530.

[4] EPA's failure to identify any meaningful improvements may explain why it sought to expand its interpretive position to non-sequiturs such as "getting new or better information." 88 Fed. Reg. at 24863 & n.15. Not only did EPA fail to justify such expanded interpretation, *see Encino Motorcars, LLC v. Navarro*, 579 U.S. 211, 220–22 (2016), but the information discussed is not even "new" since the performance levels had been generally demonstrated prior to the 2020 RTR.

A deeper inquiry into the preamble reveals EPA's pretext. To start, if any innovations truly existed and were legitimate, EPA did not identify them in the Proposed Rule—even though the Andover Report was published in 2021 and EPA uploaded the document to the rulemaking docket in 2022. Instead, the Proposed Rule cited the Andover Report to demonstrate easier cost compliance within the industry with already existing technology. 88 Fed. Reg. at 24868–69.

The "developments" the Andover Report identified (which the Final Rule referenced) could hardly be considered an evolution, advancement, or innovation. For example, EPA admits ESPs "ha[ve] not undergone fundamental changes since 2011." 89 Fed. Reg. at 38530. EPA's reference to "'best practices' associated with monitoring ESP operation more carefully" is a word-for-word parroting of what was in the Andover Report—except the Andover Report never discusses more than that. *Compare id.*, *with* Andover Report, Ex. 4, at 16.

Even the discussion on fabric filters just concerns "more widespread use" of certain materials. Rather than some breakthrough, operators were merely putting existing materials into greater deployment. The Andover Report admits that "most of the underlying engineering associated with baghouse technology has only experienced minor changes over the past decade." Andover Report, Ex. 4, at 27–28.

EPA's last-minute, one-paragraph discussion that "more durable materials have been developed" for fabric filters, 89 Fed. Reg. at 38530, and reliance on a single consultant report, illustrate that the Agency's "reasoning" was merely a box-checking afterthought. This reasoning is window dressing. *See Eagle Cnty. v. Surface Transp. Bd.*, 82 F.4th 1152, 1194–95 (D.C. Cir. 2023) ("Based on its nebulous references in the record to 'potential issues related to energy,' we should apparently create from whole cloth a reasoned consideration of the energy conservation policy. This we cannot do." (citation omitted)), *cert. granted sub nom. Seven Cnty. Coal. v. Eagle Cnty.*, No. 23-975 (U.S. June 24, 2024).

B. The Final Rule is Arbitrary and Capricious.

EPA admits, many times, that it is targeting Colstrip. "Colstrip is . . . the only facility where the EPA estimates the current controls would be unable to meet a lower fPM limit." 89 Fed. Reg. at 38531. "[O]nly two EGUs at one facility (Colstrip)" must install a completely different, "the costliest," control technology to meet the new emission standard; per EPA, every other EGU in the country either need not do anything or make minor upgrades. *Id.* at 38522. Unsurprisingly, EPA knows almost half of the regulatory burdens will fall on Colstrip alone. *See id.* at 38533 ("42 percent"); RTC, Ex. 7, at 39 (acknowledging that "compliance costs will fall disproportionately on . . . Colstrip in particular").

Yet when Petitioners raised Colstrip-focused concerns, EPA ignored most and brushed others off. EPA never seriously grappled with at least four issues regarding Colstrip. EPA "entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or [the explanation] is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *State Farm*, 463 U.S. at 43.

1. Interaction with the GHG Rule

EPA failed to consider how the Final Rule would interact with its simultaneous flagship GHG regulation. Talen Montana made clear that the ***combination*** of these two rules would complicate Colstrip's future by forcing expensive controls by 2027 (Final Rule) and then compelling retirement by the end of 2031 (GHG Rule), likely making the installation of controls cost-prohibitive and forcing an even earlier retirement. Talen Mont. Cmts., Ex. 6, at 1, 6–7. EPA ignored this dual regulation's implications on Colstrip.

The Final Rule references the GHG Rule exactly once, in the retirement subcategory context. *See* 89 Fed. Reg. at 38527. *But see* discussion *infra* pages 13–15. EPA's RTC likewise dodged Petitioners' concerns—either EPA brushed off the concern as an unrelated statutory issue, RTC, Ex. 7, at 38, 65, a premature issue, *id.* at 127, or an issue that goes to reliability concerns writ large, *id.* at 43, 130–31, 157.

Starting with EPA's first RTC response, EPA argued that because the rules are authorized from different sections of the CAA, each has "no impact" on the other, *id.* at 38, 65, notwithstanding Petitioners' comments that the interaction of the two rules on Colstrip is significant. No part of the Act allows CAA regulations to be so partitioned. Rather, EPA must "acknowledge and account for a changed regulatory posture the agency creates—especially when the change impacts a contemporaneous and closely related rulemaking."[5] *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 187 (D.C. Cir. 2011).

Next, EPA argued it "generally considers finalized, rather than proposed, rules" for its analyses. RTC, Ex. 7, at 127. But an "impending [regulation] of an undeniably related source category is clearly a 'relevant factor[]' or an 'important aspect of the problem' that must be considered." *Portland Cement*, 665 F.3d at 187. Otherwise, "newly acquired evidence" and "significant factual predicate[s]" could be brushed aside, just like EPA did so here. *See id.* Here, the two rules could not be more linked—the Administrator himself publicly touted the rules' release "on the same day."[6]

---

[5] EPA's posture is especially problematic given that the Final Rule's climate benefits were not from emission controls, but "changes in dispatch." 89 Fed. Reg. at 38557. The GHG Rule would precipitate even more significant changes in dispatch and would slash GHG emissions through its own required controls. "EPA cannot have it both ways" where the Final Rule claims credit for substantial pollutant reductions, but then excludes as being outside the Final Rule's scope a contemporaneous rule curbing those same emissions. *See Del. Dep't of Nat. Res. & Env't Control v. EPA*, 785 F.3d 1, 18 (D.C. Cir. 2015) [hereinafter *Del. DNR*] (criticizing EPA for have-it-both-ways treatment of reliability impacts).

[6] *See, e.g.*, Ella Nilsen & Jen Christensen, *Biden Administration Finalizes New Rules for Power Plants in One of Its Most Significant Climate Actions To-Date*, CNN (May 1, 2024), https://www.cnn.com/2024/04/25/climate/biden-epa-power-plant-rule-climate/index.html.

Finally, EPA treated Petitioners' argument on the GHG Rule as merely focused on reliability, and re-directed the comments to the Agency's (general) nationwide answers on that issue. *See* RTC, Ex. 7, at 43, 130–31, 157. *But see* discussion *infra* pages 15–17. Petitioners' concerns were broader than reliability (i.e., the sequencing of compliance deadlines could force a premature shutdown with wide-ranging economic impacts) and raised reliability issues unique to Montana.

"Instead of treating the two rules as truly interdependent efforts and acknowledging their close correlation, EPA let each run its own course regardless of the collateral impact." This Court should reject EPA's "ostrich-like approach." *See Portland Cement*, 665 F.3d at 185 & n.2.

2. Retirement Subcategorization

EPA also dismissed Petitioners' plea to establish a retirement subcategory harmonized with the GHG Rule. Talen Mont. Cmts., Ex. 6, at 6, 21–22; NorthWestern Cmts., Ex. 5, at 4, 24–25. Petitioners' proposal would have ameliorated the negative interactions of the two rules.

Agencies must consider—and explain the rejection of—"significant and viable" and "obvious" alternatives. *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). EPA's rationale for rejecting retirement as a subcategory falls short of this standard. According to EPA, 67 of the 296 EGUs "have announced retirements between 2029 and 2032" and "all but three" could comply with the revised standard. EPA thus inferred "little utility to a near-term retirement subcategory," claiming it would not "meaningful[ly]" change the regulatory cost. 89 Fed. Reg. at 38527.

Essentially, EPA argues that units already announcing retirement can comply, so there is no reason to provide retiring units any relief from the revised standard. However, Petitioners asked EPA to consider a retirement sub-category because (1) Colstrip does ***not*** have an announced/planned retirement date, and (2) if a suitable one was provided, Colstrip could opt to retire in an orderly fashion and avoid the cost of controls. That EPA considered only those units that already announced retirement and not ones that ***could decide to retire*** is the essence of arbitrary rulemaking, particularly given Petitioners' comments on this very topic. Critically, if EPA established a retirement subcategory and Colstrip were to retire, EPA would avoid nearly half of the rule's costs. *Id.* at 38533. Thus, EPA's assertion that the subcategory "would not change the costs of the rule in a meaningful way," *id.* at 38527, lacks any rational foundation.

Additionally, EPA states that letting units operate longer without additional controls would lead to "continued exposure to those emissions in the communities around these units during that timeframe." *Id.* But EPA has identified no meaningful risk to these communities. At best, one paragraph in the Final Rule parrots concerns reported by the Northern Cheyenne Tribe with no discussions on how exactly the tribal members have been, or could be, harmed. *Id.* at 38531. EPA certainly did not quantify the risks of exposure for such limited timeframes around Colstrip, a sparsely populated area in eastern Montana.

Moreover, in refusing to adequately consider the retirement subcategory, EPA ignored the ***benefits*** of early retirement—which cuts emissions entirely—rather than just decreasing emissions over a longer period of time based on Final Rule compliance. Thus, EPA's claim that Petitioners' suggested subcategorization would lead to higher HAP emissions is baseless. EPA's "failure to address these comments, or at best its attempt to address them in a conclusory manner, is fatal." *Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, 626 F.3d 84, 94 (D.C. Cir. 2010).

3. Grid Reliability Concerns Related to Colstrip

Off the bat, EPA declared that commenters proffered "no credible information" that the Final Rule would lead to premature retirements and "disagree[d] that this rule would threaten resource adequacy or otherwise degrade electric system reliability." 89 Fed. Reg. at 38526. This is both evasive and wrong. It is evasive because EPA's resort to national observations elides the deliberately disproportional impacts to Colstrip. It is wrong because NorthWestern alone devoted more than a third of its 25-page comments (plus exhibits) explaining how (1) upgrades to Colstrip would be cost-prohibitive, (2) closing Colstrip before the mid-2030s would create a grid reliability crisis, and (3) the diversion of funds alone for compliance would complicate meeting generation demand. *See* NorthWestern Cmts., Ex. 5, at 2–3, 13–19. EPA's "[c]onclusory explanations" notwithstanding "considerable evidence" otherwise alone warrants reversal. *AT&T Wireless Servs., Inc. v. FCC*, 270 F.3d 959, 968 (D.C. Cir. 2001).

EPA's other responses similarly omit important context. When the Final Rule represents that EGUs requiring additional control technology will "generate less than 1.5 percent of total generation in 2028," 89 Fed. Reg. at 38526, it ignores that such generation is concentrated in Montana. When EPA projects that no EGUs will retire in response to the Final Rule, *id.*, it is again ignoring the comments presented by Petitioners. The same is true for EPA's sweeping assertions based on prior experience; there is no analysis related to how the Final Rule would impact Montana. *See id.*

The one instance EPA attempts to address Petitioners' concerns about early EGU retirement and reliability, the Agency resorts to unworkable rationales. EPA assumes that NorthWestern's participation in the Western Regional Adequacy Program ("WRAP") or other entities would magically ensure sufficient replacement power. RTC, Ex. 7, at 52. This is not how WRAP functions (or could) under the regulation's timelines. *See, e.g.*, NorthWestern Cmts., Ex. 5, at 13–19 (supply and transmission limitations on power). And if WRAP or other local regulators cannot rescue Colstrip, EPA wishes the problem away by claiming that the Department of Energy might save the plant through an unprecedented application of emergency authority under the Federal Power Act.[7] *See* RTC, Ex. 7, 52.

EPA's unsupported claim that reliability authorities will fix Colstrip's unique problems (where there will not be suitable replacement generation if it retires) is either a failure to consider an important aspect of the problem, or "so implausible" as to be unreasonable. *See Am. Bankers Ass'n v. Nat'l Credit Union Admin.*, 934 F.3d 649, 669–70 (D.C. Cir. 2019) (finding agency's answers to an issue arbitrary and capricious because none of the answers addressed the particular version of the issue raised by petitioners). Ultimately, "EPA seeks to excuse its inadequate responses by passing the entire issue off onto a different agency. Administrative law does not permit such a dodge." *Del. DNR*, 785 F.3d at 16.

4. Cost-Effectiveness Analysis

Lastly, EPA's generic answers addressing Petitioners' Colstrip-specific comments resulted in a fundamentally flawed assessment of cost-effectiveness. EPA cannot turn a blind eye on important issues raised regarding flaws in its

[7] Such authority has never been used under similar circumstances. *See, e.g.*, *Duke Power Co. v. Fed. Power Comm'n*, 401 F.2d 930, 944 (D.C. Cir. 1968) (discussing how the Federal Power Act Section 202(c) "relate[s] exclusively to temporary interconnections during national emergencies"); 10 C.F.R. § 205.371 (defining "emergency" as an "unexpected inadequate supply of electricity" arising from an "unforeseen" event).

analysis. *See Owner-Operator Indep. Drivers Ass'n v. Fed. Motor Carrier Safety Admin.*, 494 F.3d 188, 205 (D.C. Cir. 2007)) (vacating a rule "when an important aspect of its methodology was wholly unexplained"). Here, EPA did so at least twice.

First, Petitioners challenged the rule's cost-effectiveness by providing detailed technical explanations that EPA overestimated how much the new control technology at Colstrip would reduce fPM. For example, Talen Montana commented that no vendor could guarantee fPM removal to the level assumed by EPA (down to 0.002 lb/mmBtu, well below the 0.010 lb/mmBtu standard set by the Final Rule). Talen Mont. Cmts., Ex. 6, at 14–16. By overestimating tons of fPM removed, the Agency artificially reduced the costs per ton of removal. As documented by Talen Montana, *id.* at 20, EPA's estimated cost-effectiveness of $39,192/ton would rise to $92,400/ton at Colstrip, highly cost-***in***effective.

Second, EPA assessed technology upgrade costs to be spread out for 15 to 18 years because EPA assumed that Colstrip is not retiring. 89 Fed. Reg. at 38526. With the GHG Rule, this is not a reasonable assumption. Petitioners provided EPA with a separate analysis that explained how, under the real risk that Colstrip's remaining life might be closer to four years, Colstrip's annualized control costs would skyrocket. Talen Mont. Cmts., Ex. 6, at 16–21 & Attachs. B, C.

Both points raised during notice and comment were ignored. EPA's "failure to 'examine the relevant data and articulate a satisfactory explanation for its action'" makes the Agency's cost-effectiveness analysis arbitrary and capricious. *Appalachian Power Co. v. EPA*, 251 F.3d 1026, 1034 (D.C. Cir. 2001). With the record in front of this Court, such determination would amount to a "serious flaw" that renders the Final Rule unreasonable. *See Window Covering Mfrs. Ass'n v. Consumer Prod. Safety Comm'n*, 82 F.4th 1273, 1288–89 (D.C. Cir. 2023).

II. Petitioners Will Suffer Immediate Irreparable Injury Absent a Stay.

By the time this litigation runs its ordinary course, Colstrip's fate will already be sealed. With a three-year compliance deadline, Petitioners face immediate, highly consequential decisions on Colstrip's future. Either Petitioners must commit to install controls costing over $350M and begin that process immediately—both internally (funding, engineering, permitting, and construction) and externally (state public utility commission proceedings)—or set a course for Colstrip's (premature) retirement. *See, e.g.*, Hines Decl., Ex. 2, at ¶ 18–24.

Either path poses irreversible and severe consequences to Petitioners and Montana as a whole, in terms of financial, consumer, and reliability impacts. Lebsack Decl., Ex. 1, at ¶¶ 51–62. Worse, these decisions must be made in consultation with four other Colstrip owners with divergent interests and regulatory mandates. *See, e.g.*, *id.* ¶¶ 13–31. A stay is necessary to avoid these irreparable harms.

A. The Final Rule Imposes Irrecoverable Costs on Colstrip.

"[F]inancial injury [can be] irreparable where no 'adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation,'" *NTE*, 26 F.4th at 990 (second alteration in original), and Colstrip's option of installing potentially unnecessary control technology is one such example. The costs associated with the irreversible decision to install controls will be exorbitant and immediate. Lebsack Decl., Ex. 1, at ¶ 36. It will cost "over $350 million" over the course of the project to install new fabric filters or ESPs, and an additional $15M in annual operating cost. *Id.* ¶¶ 34–36. And Colstrip can only comply with EPA's schedule if it starts engineering and construction activities "immediately." *See id.* ¶¶ 35–38; *cf. Ala. Ass'n of Realtors v. Dep't of Health & Hum. Servs.*, 594 U.S. 758, 765 (2021) (finding that the eviction moratorium risked "irreparable harm by depriving [landlords] of rent payments with no guarantee of eventual recovery").

In fact, Petitioners have "already" incurred costs, and costs will "ramp up" significantly in the coming months to preserve the compliance option. Lebsack Decl., Ex. 1, at ¶¶ 36, 51. NorthWestern, furthermore, is commencing a new rate recovery review to determine if the Montana Public Service Commission will allow "advance approval of rate recovery," Hines Decl., Ex. 2, at ¶ 24, a massive financial uncertainty. Accordingly, with an impending three-year deadline, Petitioners cannot wait on this litigation before getting to work on Final Rule compliance or retirement of Colstrip. Lebsack Decl., Ex. 1, at ¶ 38.

To be clear, the above-mentioned activities are "unnecessary . . . if the MATS Final Rule is overturned on appeal." *Id.* ¶ 51. The investment will be 100 percent "unrecoverable compliance costs" that the control technology does not help recuperate. *See NFIB v. OSHA*, 595 U.S. 109, 120 (2022) (per curiam).

EPA is no stranger to this playbook. *Michigan v. EPA*, 576 U.S. 743 (2015), struck down the original MATS Rule as illegal. Yet companies were forced to spend hefty sums with no recourse. This Court should not condone such unfair agency conduct.

B. The Final Rule Raises Shutdown and Grid Reliability Concerns.

The premature retirement option could inflict even more irreparable harm. Accelerated closure destabilizes Montana's grid and drives major rate hikes. Hines Decl., Ex. 2, at ¶¶ 44–47, 52; Lebsack Decl., Ex. 1, at ¶ 56–57 (discussing higher electricity prices and "reliability at risk"). Colstrip currently plays an essential role in baseload capacity for NorthWestern. *See* Hines Decl., Ex. 2, at ¶¶ 27, 41–42, 64.

There are no near-term feasible means to replace Colstrip's capacity with other existing NorthWestern capacity or market purchases from other sources. *Id.*

¶¶ 45–53, 69 (discussing insufficient transmission capacity, especially due to multiple EGU closures, and the length it would take to build new generation). Imported power is further constrained by transmission limitations. *Id.* ¶¶ 45–47. The Final Rule's mandatory closures will also force consumers to pay more for power—particularly during extreme weather events—and as skyrocketing electricity demand strains an already-vulnerable system transition. *Id.* ¶¶ 55, 59–62, 64–66.

Additionally, Colstrip's closure would mean more than 3,000 fewer jobs, $240.3M loss of income per year for Montana households, and about $102.8M less in State tax revenue per year (excluding impacts to the local property and coal gross proceeds tax). Montana would also suffer overall reduced economic activity (worth over $1B) due to electricity cost/reliability, reduced inter-region trade, and lower State government spending. Lebsack Decl., Ex. 1, at ¶ 58 & Attach. C; Talen Mont. Cmts., Ex. 6, at 6–7.

III. The Balance of Equities and the Public Interest Strongly Favor a Stay.

All the stay does is preserve the status quo. EPA found the status quo to provide "an ample margin of safety to protect public health." 89 Fed. Reg. at 38518.

Public interest strongly favors a stay, given the low cost-effectiveness of the Final Rule, the lack of public health benefits, and especially when the Final Rule could risk electricity access. *See, e.g.*, *Texas v. EPA*, 829 F.3d 405, 435 (5th Cir. 2016); *West Virginia v. EPA*, 90 F.4th 323, 332 (4th Cir. 2024).

It is unclear what public interest exists for a regulation that admitted there is a "negative net monetized benefit" while other categories of benefits were not quantified. 89 Fed. Reg. at 38511. *See generally Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 233 (2009) (Breyer, J., concurring in part and dissenting in part) ("[T]oo much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems."). In any event, "our system does not permit agencies to act unlawfully even in pursuit of desirable ends." *Ala. Ass'n Realtors*, 594 U.S. at 766.

CONCLUSION

Petitioners request the Court to stay the Final Rule.

DATED: June 27, 2024

Respectfully submitted,

/s/ Joshua B. Frank

Joshua B. Frank
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street N.W.
Washington, D.C. 20001
Tel.: (202) 639-7748
(202) 639-1130
joshua.frank@bakerbotts.com
joshua.lee@bakerbotts.com

Counsel for Petitioner Talen Montana, LLC

/s/ Michael Drysdale

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue N.W.,
Suite 900
Washington, D.C. 20005
Tel.: (202) 442-3555
magid.chip@dorsey.com

Michael Drysdale (*Of Counsel*)
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402
Tel.: (612) 340-5652
drysdale.michael@dorsey.com

Counsel for Petitioner
NorthWestern Corporation
d/b/a NorthWestern Energy

CERTICIATE OF PARTIES AND AMICI CURIAE

Pursuant to D.C. Circuit Rules 18(a)(4), 27, and 28(a)(1)(A), Petitioners certify as follows.

At the time of this filing, below are the parties, intervenors, and amici curiae to this case and the related cases, including the lead case, *North Dakota v. EPA*, No. 24-1119 (D.C. Cir. filed May 8, 2024).

1. Parties, Intervenors, and Amici to this Case.

Petitioners: Talen Montana, LLC (No. 24-1190), and NorthWestern Corporation d/b/a NorthWestern Energy (No. 24-1217).

Respondents: U.S. Environmental Protection Agency, and Michael S. Regan as Administrator of the U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

2. Parties, Intervenors, and Amici to Related Cases.

a. *North Dakota v. EPA*, No. 24-1119 (D.C. Cir. filed May 8, 2024).

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

Respondents: U.S. Environmental Protection Agency.

Intervenors in Support of Respondents: (1) Air Alliance Houston, Alliance of Nurses for Healthy Environments, American Academy of Pediatrics, American Lung Association, American Public Health Association, Chesapeake Climate Action Network, Citizens for Pennsylvania's Future, Clean Air Council, Clean Wisconsin, Downwinders at Risk, Environmental Defense Fund, Environmental Integrity Project, Montana Environmental Information Center, Natural Resources Council of Maine, Natural Resources Defense Council, the Ohio Environmental Council, Physicians for Social Responsibility, and Sierra Club; (2) Commonwealth of Massachusetts, State of Minnesota, State of Connecticut, State of Illinois, State of Maine, State of Maryland, State of Michigan, State of New Jersey, State of New York, State of Oregon, Commonwealth of Pennsylvania, State of Rhode Island, State of Vermont, State of Wisconsin, District of Columbia, City of Baltimore, City of Chicago, City of New York.

Intervenors in Support of Petitioners: San Miguel Electric Cooperative, Inc.

Amici: None.

b. *NACCO Natural Resources Corporation v. EPA*, No. 24-1154 (D.C. Cir. filed May 22, 2024).

Petitioners: NACCO Natural Resources Corporation.

Respondents: U.S. Environmental Protection Agency, and Michael S. Regan as Administrator of the U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

c. *National Rural Electric Cooperative Association v. EPA*, No. 24-1179 (D.C. Cir. filed June 3, 2024).

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

Respondents: U.S. Environmental Protection Agency, and Michael S. Regan, in his official capacity as Administrator of the U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

d. *Oak Grove Management Company LLC v. EPA*, No. 24-1184 (D.C. Cir. filed June 6, 2024).

Petitioners: Oak Grove Management Company LLC, and Luminant Generation Company, LLC.

Respondents: U.S. Environmental Protection Agency, and Michael S. Regan as Administrator of the U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

e. *Westmoreland Mining Holdings LLC v. EPA*, No. 24-1194 (D.C. Cir. filed June 11, 2024).

Petitioners: Westmoreland Mining Holdings LLC.

Respondents: U.S. Environmental Protection Agency, and Michael S. Regan as Administrator of the U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

f. *America's Power v. EPA*, No. 24-1201 (D.C. Cir. filed June 14, 2024).

Petitioners: America's Power, and Electric Generators MATS Coalition.

Respondents: U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

g. *Midwest Ozone Group v. EPA*, No. 24-1223 (D.C. Cir. filed June 27, 2024).

Petitioners: Midwest Ozone Group.

Respondents: U.S. Environmental Protection Agency, and Michael S. Regan as Administrator of the U.S. Environmental Protection Agency.

Intervenors and Amici: None except for those in the lead case.

DATED: June 27, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

CERTIFICATE OF COMPLIANCE

Pursuant to Federal Rule of Appellate Procedure 32(g), I certify as follows.

1. Petitioners' Joint Motion for Stay complies with the word limit set in Federal Rule of Appellate Procedure 27(d)(2)(A) because, excluding the exempted parts, *see* Fed. R. App. P. 27(a)(2)(B), 32(f); D.C. Circ. R. 32(e)(1), this document contains **5,197** words according to the word count of the word-processing system used to prepare the document (Microsoft Word).

2. This document complies with Federal Rule of Appellate Procedure 32(a)(5) and (6) because it has been prepared using Microsoft Word in 14-point, proportionally spaced, Times New Roman font.

Additionally, pursuant to Federal Rule of Appellate Procedure 18(a) and D.C. Circuit Rule 18(a), I certify as follows.

1. Petitioners requested EPA to stay the Final Rule pending judicial review on June 25, 2024. As of the filing of this motion, EPA has not acted on that request.

2. Petitioners provided notice via email to all parties involved in the consolidated case that Petitioners will be filing a stay motion.

3. Petitioners attached "originals or copies of affidavits or other sworn statements supporting facts subject to dispute" (Exhibits 1, 2), "relevant parts of the record" (Exhibits 3 to 8), and "a copy of the order involved, and of any pertinent

rule, decision, memorandum, opinion, or findings issued by the agency" (Exhibits 3, 7, 8). *See* Fed. R. App. P. 18(a)(2)(B); D.C. Cir. R. 18(a)(3).

DATED: June 27, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

CORPORATE DISCLOSURE STATEMENT

Pursuant to D.C. Circuit Rules 18(a)(4) and 27(a)(4), Petitioners submit the following disclosure statement as described in Federal Rule of Appellate Procedure 26.1 and D.C. Circuit Rule 26.1.

Talen Montana, LLC is a power generation company, which operates and partially owns Colstrip Unit 3 (and has an economic interest in Colstrip Unit 4), which are power plant units affected by EPA's final action subject to this Petition for Review. Talen Montana, LLC is an indirect, wholly owned subsidiary of Talen Energy Corporation. Talen Energy Corporation is a publicly traded corporation. No publicly held company owns more than 10% of Talen Energy Corporation's stock.

NorthWestern Corporation d/b/a NorthWestern Energy is a wholly owned subsidiary of NorthWestern Energy Group, a publicly traded company (Nasdaq: NWE) that is incorporated in Delaware. Based on a June 21, 2024, review of the most recent statements filed with the Securities and Exchange Commission pursuant to Sections 13(d), 13(f), and 13(g) of the Securities Exchange Act of 1934, two publicly held companies own 10% or more of NorthWestern Energy Group's stock: BlackRock Inc. and Vanguard Group Inc.

DATED: June 27, 2024 Respectfully submitted,

/s/ Joshua B. Frank */s/ Michael Drysdale*

Joshua B. Frank
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street N.W.
Washington, D.C. 20001
Tel.: (202) 639-7748
(202) 639-1130
joshua.frank@bakerbotts.com
joshua.lee@bakerbotts.com

Counsel for Petitioner
Talen Montana, LLC

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue N.W.,
Suite 900
Washington, D.C. 20005
Tel.: (202) 442-3555
magid.chip@dorsey.com

Michael Drysdale (*Of Counsel*)
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402
Tel.: (612) 340-5652
drysdale.michael@dorsey.com

Counsel for Petitioner
NorthWestern Corporation
d/b/a NorthWestern Energy

CERTIFICATE OF SERVICE

I certify that on June 27, 2024, the foregoing Joint Motion for Stay and the accompanying Attachments were served electronically on all registered counsel through the Court's CM/ECF system.

DATED: June 27, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

ORAL ARGUMENT NOT YET SCHEDULED

Nos. 24-1201 (consolidated with No. 24-1119)

In the United States Court of Appeals for the District of Columbia Circuit

AMERICA'S POWER
AND
ELECTRIC GENERATORS MATS COALITION,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

PETITIONERS' MOTION FOR STAY PENDING JUDICIAL REVIEW

Makram B. Jaber
Allison D. Wood
Aaron M. Flynn
MCGUIREWOODS LLP
888 16th Street N.W., Suite 500
Black Lives Matter Plaza
Washington, DC 20006
(202) 857-1700
mjaber@mcguirewoods.com

Counsel for Petitioners America's Power and Electric Generators MATS Coalition

CERTIFICATE AS TO PARTIES

Pursuant to Circuit Rules 18(a)(4), 27(a)(4), and 28(a)(1)(A), Petitioners America's Power and Electric Generators MATS Coalition submit this certificate as to parties.

A. <u>Parties and Amici</u>. Because these consolidated cases involve direct review of final agency action, the requirement to furnish a list of parties, intervenors, and *amici* that appeared below is inapplicable. These cases involve the following parties:

<u>Petitioners:</u>

No. 24-1119: State of North Dakota, State of West Virginia, State of Alaska, State of Arkansas, State of Georgia, State of Idaho, State of Indiana, State of Iowa, State of Kansas, Commonwealth of Kentucky, State of Louisiana, State of Mississippi, State of Missouri, State of Montana, State of Nebraska, State of Oklahoma, State of South Carolina, State of South Dakota, State of Tennessee, State of Texas, State of Utah, Commonwealth of Virginia, and State of Wyoming.

No. 24-1154: NACCO Natural Resources Corporation.

No. 24-1179: National Rural Electric Cooperative Association, Lignite Energy Council, National Mining Association, Minnkota Power Cooperative, Inc., East Kentucky Power Cooperative, Inc., Associated Electric Cooperative Inc., Basin Electric Power Cooperative, and Rainbow Energy Center, LLC.

No. 24-1184: Oak Grove Management Company, LLC and Luminant Generation Company LLC.

No. 24-1190: Talen Montana, LLC.

No. 24-1194: Westmoreland Mining Holdings LLC, Westmoreland Mining LLC, and Westmoreland Rosebud Mining LLC.

No. 24-1201: America's Power and Electric Generators MATS Coalition.

No. 24-1217: NorthWestern Corporation d/b/a NorthWestern Energy.

No. 24-1223: Midwest Ozone Group.

Respondents:

The United States Environmental Protection Agency ("EPA").

Michael S. Regan, Administrator of the United States Environmental Protection Agency.

<u>Intervenors and *Amici*:</u>

In 24-1119 and all consolidated cases: San Miguel Electric Cooperative, Inc., in support of Petitioners.

In 24-1119 and all consolidated cases: Environmental and Public Health Organizations (Air Alliance Houston, Alliance of Nurses for Healthy Environments, American Academy of Pediatrics, American Lung Association, American Public Health Association, Chesapeake Climate Action Network, Citizens for Pennsylvania's Future, Clean Air Council, Clean Wisconsin, Downwinders at Risk, Environmental Defense Fund, Environmental Integrity Project, Montana Environmental Information Center, Natural Resources Council of Maine, Natural Resources Defense Council, the Ohio Environmental Council, Physicians for Social Responsibility, and Sierra Club), Commonwealth of Massachusetts, State of Minnesota, State of Connecticut, State of Illinois, State of Maine, State of Maryland, State of Michigan, State of New Jersey, State of New York, State of Oregon, Commonwealth of

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

/s/ *Makram B. Jaber*
Makram B. Jaber

Certificate of Compliance with Circuit Rules 18(a)(1) and (a)(2)

The undersigned certifies that this motion for stay complies with Circuit Rule 18(a)(1). Petitioners America's Power and Electric Generators MATS Coalition submitted a Petition for Administrative Stay Pending Judicial Review to the United States Environmental Protection Agency ("EPA") on July 5, 2024. EPA has not acted on that request. Therefore, Petitioners now seek a stay from this Court. In accordance with Circuit Rule 18(a)(2), undersigned counsel notified EPA's counsel (as well as all parties) by email on July 6, 2024, that Petitioners planned to file this motion for stay.

<u>/s/ Makram B. Jaber</u>
Makram B. Jaber

RULE 26.1 DISCLOSURE STATEMENTS

AMERICA'S POWER

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and D.C. Circuit Rule 26.1, America's Power submits the following statement:

America's Power is a nonprofit membership corporation organized under the laws of the District of Columbia and is recognized as a tax-exempt trade association by the Internal Revenue Service under Section 501(c)(6) of the Internal Revenue Code. America's Power is the only national trade association whose sole mission is to advocate at the federal and state levels on behalf of coal-fueled electricity, the coal fleet, and its supply chain. America's Power supports policies that promote the use of coal to assure a reliable, resilient, and affordable supply of electricity to meet our nation's demand for energy.

America's Power is a "trade association" within the meaning of Circuit Rule 26.1(b). It has no parent corporation, and no publicly held company owns a 10% or greater interest in America's Power.

ELECTRIC GENERATORS MATS COALITION

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and D.C. Circuit Rule 26.1, Electric Generators MATS Coalition submits the following statement:

Electric Generators MATS Coalition is an *ad hoc* coalition of electric generating companies that have joined together for the purpose of filing this petition for review. The members of the *ad hoc* coalition own and operate electric generating units that are subject to the Final Rule at issue in this case. The members of the *ad hoc* coalition are the Salt River Project Agricultural Improvement and Power District; Talen Energy Supply, LLC; and NorthWestern Energy Public Service Corporation.

Electric Generators MATS Coalition has no parent corporation, and no publicly held corporation has a 10% or greater ownership in it.

Dated: July 8, 2024

Respectfully submitted,

/s/ Makram B. Jaber
Makram B. Jaber
Allison D. Wood
Aaron M. Flynn
MCGUIRE WOODS LLP
888 16th Street N.W., Suite 500
Black Lives Matter Plaza
Washington, DC 20006
(202) 857-1700
mjaber@mcguirewoods.com
awood@mcguirewoods.com
aflynn@mcguirewoods.com

Counsel for Petitioners America's Power and Electric Generators MATS Coalition

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

CASES

STATUTES

REGULATIONS

OTHER AUTHORITY

GLOSSARY

Acronym	Meaning
EGU	Electric generating units
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
fPM	Filterable Particulate Matter
HAP	Hazardous Air Pollutant
MATS	Mercury and Air Toxics Standards
MIR	Maximum Individual Risk
RTR	Risk and Technology Review

Introduction

A few days ago, the Supreme Court stayed a major Environmental Protection Agency ("EPA") regulation, after finding the rule likely arbitrary and capricious and "the harms and equities [to be] very weighty on both sides." *Ohio v. EPA*, No. 23A349 (and consolidated cases), slip op. at 10 (June 27, 2024) (quotation omitted). The instant rule causes substantial, irreparable harm to coal-fired electric generating units ("EGUs") and the states in which they operate, in return for, at most, a trivial benefit attributable to their hazardous air pollutant ("HAP") emissions. As other Movants have shown, the rule likely violates Section 112 of the Clean Air Act, 42 U.S.C. §7412, and is unlawful.[1] The Court should stay this rule.

Background

EPA's 2012 Mercury and Air Toxics Standards ("MATS") regulate HAP emissions from oil- and coal-fired EGUs under Section 112 of the Clean

[1] Heeding this Court's order regarding avoiding duplication and repetition in stay motions, ECF#2062459, Petitioners America's Power and Electric Generators MATS Coalition (collectively, "Petitioners") present arguments not addressed or fully addressed by other Movants and adopts the following stay motions: ECF#2058570; ECF#2061137; ECF#2062093; and ECF#2062097.

Air Act. 77 Fed. Reg. 9,304 (Feb. 16, 2012). The instant "Risk and Technology Review" ("RTR") rule revises MATS under Section 112(d)(6), 42 U.S.C. §7412(d)(6). Specifically, EPA revised the coal-fired EGU filterable particulate matter ("fPM") standard—which is used a surrogate for non-mercury metal HAPs—and the lignite-coal-fired EGU mercury standard. 89 Fed. Reg. 38,508 (May 7, 2024) ("Rule"). Other movants have thoroughly described the twists and turns of this program's regulatory history and the standard for a stay, so we do not repeat them here.[2]

ARGUMENT

This Rule, much like most EPA rules, involves technical issues. Deciding such issues is difficult, and even more so on a motion for stay "because it can require the Court to assess the merits … earlier and more quickly than is ordinarily preferable, and to do so without the benefit of full merits briefing and oral argument." *Labrador v. Poe*, 144 S.Ct. 921, 928 (2024) (Kavanaugh,

[2] This motion primarily addresses EPA's fPM standard revision. We adopt other Movants' discussion and arguments relating to the lignite-coal-fired EGU mercury standard.

J., concurring). When resolving stay motions, courts "cannot avoid that difficulty. It is [perhaps] not ideal, but it is reality." *Id.*

Here, the Court must "endeavor[] to consider thoroughly the claims" presented, even though "the volume and technical complexity of the material necessary for [its] review [could be] daunting…." *Sierra Club v. Costle*, 657 F.2d 298, 314-15 (D.C. Cir. 1981) (footnote omitted). No matter how technically complex the analysis may be, the agency nevertheless must meet its "burden to consider all relevant factors and to identify the stepping stones to its final decision. There must be a rational connection between the factual inputs, modeling assumptions, modeling results and conclusions drawn from these results." *Id.* at 333 (citations omitted). EPA must "examine key assumptions as part of its affirmative burden of promulgating and explaining a nonarbitrary, non-capricious rule." *See Appalachian Power Co. v. EPA*, 135 F.3d 791, 818 (D.C. Cir. 1998) (quotation omitted).

The Rule fails to meet these standards. Petitioners are likely to succeed on the merits. Absent a stay, the Rule causes irreparable harm to Petitioners and the industry. A stay would cause no harm to the public, and the public interest favors a stay. The Court should stay the Rule.

I. Petitioners Are Likely to Prevail on the Merits.

A. A Rational Rule Cannot Impose Hundreds of Millions of Dollars in Economic Costs in Return for Trivial Benefits.

Administrative law and common sense dictate it is irrational to promulgate a rule costing hundreds of millions of dollars when no benefits result from reducing the targeted pollutants. As the Supreme Court admonished in *Michigan v. EPA*, which involved the review of MATS, the "[c]onsideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages *and* disadvantages of agency decisions." 576 U.S. 743, 753 (2015). The Court faulted EPA's refusal to "consider whether the costs of its decision outweighed the benefits," *id.* at 750, explaining "[o]ne would not say that it is even rational … to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Id.* at 752.

It is well-established that cost *is* a major consideration in technology review rulemakings like the Rule. *See, e.g.*, *Ass'n of Battery Recyclers, Inc. v.*

EPA, 716 F.3d 667, 673 (D.C. Cir. 2013). Under *Michigan*, therefore, EPA must consider the costs of *this* regulation in relation to benefits intended by Congress in Section 112 mandating *this* regulation—protecting public health from HAPs. *See* 576 U.S. at 751. Moreover, this is not just any source category; it is the category *Michigan* examined and Congress singled out for regulation only upon a determination that it is "appropriate and necessary" to do so. *Id.* at 743; 42 U.S.C. §7412(n)(1)(A). Because *Michigan* held cost and benefits must be considered in determining whether it is "appropriate and necessary" to regulate EGUs under Section 112 in the first place, it necessarily follows that the same consideration must also apply in this rulemaking, which is merely a follow-on to the initial rulemaking.

The statutory purpose of Section 112 is not reduction of HAP emissions for the sake of reduction, as EPA claims, *see* 89 Fed. Reg. at 38,525 ("Congress sought to minimize the emission of hazardous air pollution wherever feasible…."). It is to protect the public from the potential effects of HAPs. The best (maybe only) way to assess the impact of non-mercury metal HAP emissions—which are carcinogenic compounds—is to look at cancer risk. For that, a maximum individual risk ("MIR") of 1-in-1-million *is* the gold standard.[3] Indeed, Congress applied that gold standard to HAPs regulation under Section 112 by adopting it as the ultimate yardstick in Section 112(f)[4] and as the threshold below which an entire source category could be delisted, i.e., not regulated at all under Section 112.[5]

Here, only three *oil*-fired units in Puerto Rico exceed the 1-in-1-million standard. *See* 85 Fed. Reg. 31,286, 31,319 (May 22, 2020). Yet, the Rule targets only *coal*-fired *EGUs*, all with cancer risks less than 1-in-1-million.

---

[3] "The MIR is defined as the cancer risk associated with a lifetime [(70 years)] of [continuous] exposure at the highest concentration of HAP where people are likely to live." EPA, *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, at 10, 15 (Sept. 2019) (Docket ID EPA-HQ-OAR-2018-0794-4553) ("MATS Risk Assessment").

[4] 42 U.S.C. §7412(f)(2).

[5] 42 U.S.C. §7412(c)(9). The origins of the 1-in-1-million standard is a U.S. Food & Drug Administration rulemaking where the agency determined that standard "can properly be considered of insignificant public health concern." 42 Fed. Reg. 10,412, 10,421 (Feb. 22, 1977). Congress and agencies have since extensively used it as the gold standard for risk evaluation.

Moreover, as the table below shows, the coal-fired EGUs that EPA identified as potentially needing upgraded controls or increased operations and maintenance spending to meet the fPM standard have cancer risks ranging from 0.002 to 0.3 in one million—about 1-3 orders of magnitude below 1-in-1-million.[6] Further, these units have cancer incidences[7] ranging from 0.00000203 to 0.00144 excess cancer cases per year, which is equivalent to one excess case in every 492,610 to 714 years. Collectively, these units have an aggregate cancer incidence of 0.00269 excess cancer cases per year, or one excess case every 371 years.

---

[6] The table provides EPA's risk assessment results for the identified EGUs. *See* MATS RISK ASSESSMENT, App. 10, Tables 1 and 2a. The MIR is expressed in scientific format in EPA's document; we express it here in non-scientific format (e.g., for Colstrip, EPA's report says 1.47E-07, which equals 0.147-in-1-million).

[7] "Cancer incidence" is the number of excess cancer cases per year, taking into account the exposure and the population exposed. The inverse of cancer incidence is the number of years it takes to have one excess cancer case. *See* 84 Fed. Reg. 15,046, 15,060 (Apr. 21, 2019) ("The total estimated cancer incidence from this source category is 0.04 excess cancer cases per year, or one excess case in every 25 years [1/0.4=25].").

Cancer Risk for Coal-Fired Units that EPA Identified as Needing Additional Action Under the Rule

Plant Name	Cancer MIR (in 1 million)	Cancer Incidence
Seminole	0.309	0.000259
Marion	0.0849	0.0000280
Mill Creek	0.0470	0.000136
D B Wilson	0.144	0.0000603
Red Hills Generating	0.0863	0.0000234
Labadie	0.250	0.00144
Colstrip	0.147	0.0000582
Roxboro	0.0415	0.0000271
Mayo	0.0877	0.0000269
Milton R Young	0.0524	0.0000153
Colver Power Project	0.0486	0.0000184
Mt Carmel Cogen	0.0624	0.0000595
Gilberton Power Co.	0.0412	0.0000377
Westwood Generation	0.00208	0.00000203
St. Nicholas	0.0989	0.000104
Martin Lake	0.137	0.000115
Mt Storm	0.135	0.0000240
Harrison	0.344	0.000299
Laramie River Station	0.134	0.00000246
Jim Bridger	0.0674	0.00000784

Reducing cancer risk that is already less than 1-in-1-million yields a very small benefit, if any. Indeed, Congress provided a mechanism to delist source categories if their emissions' cancer risk falls below 1-in-1-million. 42 U.S.C. §7412(c)(9)(B)(i). Reducing cancer risk that is already 1 to 3 orders of magnitude below 1-in-1-million yields such an infinitesimal benefit that it is practically zero.

The hundreds of millions of dollars this Rule requires powerplants to expend for this infinitesimal benefit, at best eliminating one excess cancer case every 371 years, is not a rational result from reasoned decision-making. An irrational regulation cannot stand. *Michigan*, 576 U.S. at 750.

B. The Rule Is Arbitrary and Capricious Because It Rests on a Deeply Flawed Technical Foundation, Does Not Account For a Compliance Margin, and Results in an fPM Standard That Is Highly Cost *In*effective.

1. The Revised fPM Standard's Technical Foundation is Deeply Flawed.

In the proposal, EPA based its analysis of the performance of coal-fired EGUs and their likely needed actions and/or controls on an irrationally truncated and arbitrary selection of fPM data. In assigning an fPM emission rate to the units, EPA reviewed the rates measured in no more than two quarters in 2017, 2019, and for a handful of units in 2021. EPA, *2023 Technology Review for the Coal- and Oil-Fired EGU source Category*, at 2 (Jan. 2023) (Docket ID EPA-HQ-OAR-2018-0794-5789) ("2023 Technology Memo").

EPA provided no reasoned explanation for why it selected these quarters, even though EPA has compliance data for every quarter EGUs have operated since 2017.[8] EPA merely says its data "selection aimed to include recent compliance years during quarters with typically higher electricity demand (winter and summer)." EPA, *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo)*, at 3 (Jan. 2024) (Docket ID EPA-HQ-OAR-2018-0794-6919). Commenters pointed to the lack of a rationale for EPA's selection methodology and submitted data showing how variable the data are and demonstrating how unrepresentative EPA's data selection was.

In the Rule, EPA conceded the data it selected in the proposal were not representative and that a broader set of data "exhibited large variability

---

[8] MATS requires reporting of quarterly compliance data to EPA.

within quarters and annually." *Id.* at 5. EPA then devised a brand new methodology to parse the still-truncated dataset it was willing to review.[9] This methodology rests on a new key assumption: if a unit has *ever* emitted less than a standard, EPA assumes the unit will be able to meet that standard *continuously* either without *any* new expenditures or with an additional, small operations and maintenance expenditure of $100,000 per year.[10] *Id.* at 15.

As EPA did with its previous assumption in the proposal, EPA fails to explain or support this fundamental new assumption. It is just a naked statement in a memorandum, nothing more. *Cf. Ohio*, slip op. at 14, 17 (granting stay of EPA rule where EPA's response to a concern raised by commenters

---

[9] EPA continued to refuse to look at all the data it has, because it was too "time-consuming." *Id.* at 3. But "[t]he technical complexity of the analysis does not relieve the agency of the burden to consider all relevant factors." *Costle*, 657 F.2d at 333.

[10] EPA assumes, again with no support whatsoever, that such a unit would be able to meet the standard continuously without any new expenditures if the unit's average emissions rate, based on whatever truncated dataset EPA has for that unit, was less than the standard. If the unit's average emission rate was more than the proposed standard, EPA assumes the unit will meet the standard continuously by expending about $100,000 per year.

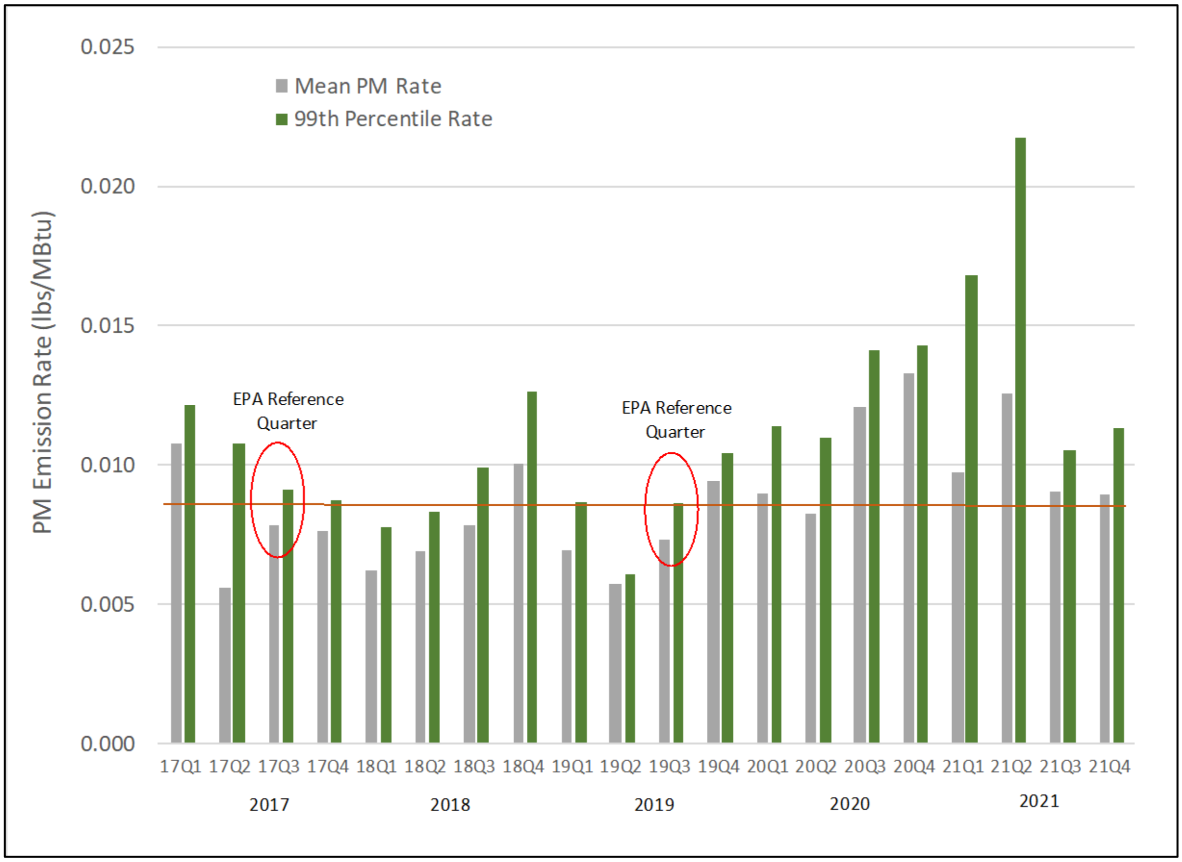
"in no way grappled with their concern" and "did not address the … concern so much as sidestep it.").

EPA's failure to support its assumption with any data whatsoever, much less some analysis or any explanation, is, at a minimum, a failure to explain. *Id.* at 13 (EPA's failure to explain means regulation likely unlawful). "The EPA had a duty here to examine and justify the 'key assumptions' underlying its decision, and it failed to do so." *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 650 (D.C. Cir. 2016) (quoting *Appalachian Power*, 135 F.3d at 818). That is textbook arbitrary and capricious rulemaking. *Id*.

Data from the Coronado Generating Station (owned by a Coalition member), submitted to EPA in comments,[11] illustrate the lack of support and justification for EPA's key assumptions:

[11] Comments of Power Generators Air Coalition, at 15 (June 23, 2023) (Docket ID EPA-HQ-OAR-2018-0794-5994) ("PGen Comments").

Coronado Generating Station 20 Operating Quarters



In the proposal, EPA examined the performance of Coronado during two quarters: 17Q3 and 19Q3, and it selected the performance of the plant in 19Q3 as representative. Commenters showed (along with many other, similar examples) that Coronado's 19Q3 performance was not representative and, indeed, unusual.[12] Sixteen of the 20 quarters reported showed fPM rates

[12] *Id.* The Coronado owner also submitted comments explaining that Coronado operated at high load continuously during that quarter, which allowed

that exceeded the 19Q3 rates, some by 100%. Moreover, the comments explained—along with supporting information—that there was no difference in the Electrostatic Precipitator ("ESP") maintenance done before 19Q3 than that done before 20Q3, yet the 20Q3 rate was much higher. PGen Comments at 14-15. In addition to inherent variability, fPM rates are affected by "myriad factors, likely chief among them the units' duty and coal variability." *Id.* at 15.

In the Rule, EPA's new methodology simply assumes Coronado *can* meet the limit of 0.01 lb/mmBtu without even increased maintenance, because, in one of the 20 quarters, Coronado had a rate as low as 0.0061 lb/mmBtu and had an average for all 20 quarters of slightly under the new standard (0.01 lb/mmBtu). 2024 Technical Memo, Attach. 1. This utterly ignores that Coronado had an entire year (20Q3 to 21Q2), where the rate was well above 0.01 lb/mmBtu for all four quarters, averaging about 0.17

Coronado to avoid "cold starts" and ramping output up and down, thus reducing fPM emissions rates. Comments of Salt River Project, at 3-4 (June 21, 2023) (Docket ID EPA-HQ-OAR-2018-0794-5936). Those are not representative operations for Coronado. *Id.*

lb/mmBtu and reaching about 0.023 lb/mmBtu in 21Q2. EPA provides no explanation in the record why Coronado's rate was much higher than its historic lowest rate for a whole year and why EPA believes Coronado could have met the revised standard without substantial work; just a bald statement that Coronado can meet the standard in the future because it did it once or twice previously. This is like a coach telling his star baseball player, who once hit three home runs in a single game and averaged one home run a game for the last season, that he must now hit two home runs each game going forward. After all, his ability to hit three home runs in one game is demonstrated, and he averaged one home run a game last season. The coach says that if the player consistently follows the same training regimen he followed before the game in which he hit three home runs, then this should be no problem. This is what EPA is expecting from EGUs under the Rule.

There is nothing in the record to support EPA's conclusion that Coronado could have met the 0.01 lb/mmBtu during that year without equipment upgrade. More important, there is no support for EPA's conclusion that Coronado will be able to meet the standard without an equipment upgrade indefinitely in the future. EPA just *assumed* it, without any basis or explanation. Coronado cannot simply *assume*; it must conduct an engineering study to figure it out, and then it will have to upgrade its ESP by 2027 if the study concludes that is needed—at a cost far in excess of the $0 EPA assigned Coronado.

These unsupported assumptions are central to the Rule and are not harmless error. If the data selection criteria for EPA's analysis are arbitrary and unsupported, the number of units that would have to upgrade to meet the new standard is also arbitrary and unsupported; the cost of upgrades across the industry is arbitrary and unsupported; and the cost-effectiveness results are arbitrary and unsupported.

EPA's decision to turn a "blind eye" to relevant information, for Coronado as well as all for other units (e.g., the fPM emissions data for 20 quarters already in EPA's possession, instead of a few arbitrary quarters of data) and its refusal to account for, or even investigate, the reasons for unit performance variability is arbitrary and capricious. *Nat. Res. Def. Council v. EPA*, 808 F.3d 556, 574 (D.C. Cir. 2015). The inherent variability of EGU emission rates, the reasons for variability, and what actions EGUs must take to meet a new, much tighter standard continuously are "an important aspect of the problem;" EPA cannot assume it away. Its failure to consider it is arbitrary and capricious. *See Motor Vehicle Mfrs. Ass'n v. State Farm Auto Mut. Ins. Co.*, 463 U.S. 29, 43 (1983).

2. EPA's Refusal to Account for a Compliance Margin is Unreasonable.

EPA based its cost calculations and cost "analysis," such as it is, on its assumption that if a unit ever met a 0.01 lb/mmBtu fPM emission rate in the past, it can meet that rate again, continuously, without upgrading controls. But EPA knows full well no prudent operator runs a unit without a compliance margin. Nevertheless, EPA refused to account for it. EPA's rationale for ignoring compliance margins in the Rule is little more than an admission it is abdicating its responsibility to fully consider the problem before it. That is unlawful. *State Farm*, 463 U.S. at 43.

EPA has long recognized the central importance of compliance margins: "when developing standards [under Section 112], we take into account the uncertainty associated with measuring emissions and we assume that plants operate with a compliance buffer to minimize the likelihood of exceeding the standard." 77 Fed. Reg. 58,220, 58,231 (Sept. 19, 2012). In its 2011 MATS proposal, EPA explained "the numerical standard should account for variability … and provide sufficient compliance margin for owners/operators …." 76 Fed. Reg. 24,976, 25,066 (May 3, 2011). In another HAP rulemaking, EPA established a standard "at a level higher than all measured values (to account for the inability to reliably measure any lower standard) and [to] … provide[] an ample compliance margin." 75 Fed. Reg. 54,970, 54,984 (Sept. 9, 2010). EPA also accounts for compliance margin outside of Section 112. *See, e.g.*, 78 Fed. Reg. 29,816, 29,881 (May 21, 2013) (discussing compliance margin typical for motor vehicle industry and explaining a margin is necessary to account for variability in emissions).

Here, commenters alerted EPA the proposal lacked the necessary compliance margin, meaning EPA's cost calculations were inaccurate as a result. *See* Summary of Public Comments and Responses on Proposed Rule, at 47-48 (Apr. 2024) ("RTC"). Indeed, EPA itself recognized the need for a compliance margin in other aspects of *this* rulemaking. In a memorandum, prepared for the original MATS rule, EPA recognized "facility operators normally target an operating level that is 25 to 50 percent lower than the emission limit in order to create a 'margin of error.'" EPA, *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*, at 1 (Nov. 16, 2012) (Docket ID EPA-HQ-OAR-2009-0234-20223). And in a memorandum seeking to shore up its decision to require fPM continuous monitoring systems in this Rule, EPA found again that a compliance margin of 50% was appropriate. EPA, *PM CEMS Random Error Contribution by Emission Limit*, at 2 (Mar. 22, 2023) (Docket ID EPA-HQ-OAR-2018-0794-5786) ("PM CEMS Memo") (noting "an operational target limit … [of] one-half of the emission limit" and setting "target compliance levels" at half the limit).

Despite all of this, EPA refused to take a compliance margin into account. EPA says it must ignore this information because (1) whether to adopt a compliance margin is in "the sole decision of owners and operators," and (2) EPA does not have data showing all sources will adopt the same compliance margin. 89 Fed. Reg. at 38,521. This has never stopped EPA before. EPA regularly accounts for factors outside its control in rulemaking. It is required by law to do so. *Miami–Dade Cnty. v. EPA*, 529 F.3d 1049, 1065 (11th Cir. 2008) ("EPA is compelled to exercise its judgment in the face of scientific uncertainty unless that uncertainty is so profound that it precludes any reasoned judgment."). EPA has information on which to act. It has taken similar action in the past. Now it refuses to do so with the thinnest of justifications.

Demonstrating just how plausible it would have been to account for a compliance margin and accurately assess the Rule's impacts, EPA begrudgingly assumes for the sake of argument, and then dismisses, a 20% margin. EPA states:

> [A] 20 percent compliance margin assumption to a fPM limit of 0.010 lb/MMBtu would increase the number of affected EGUs from 33 to 53 … and the annual compliance costs from $87.2M to $147.7M. The number of EGUs that demonstrated an ability to meet the lower fPM limit, but do not do so on average and therefore would require O&M [(operation and maintenance)], would increase from 17 to 27 (including the compliance margin). Similarly, the number of ESP upgrades (previously 11) and bag upgrades (previously 3) would also increase (to 20 and 4,

> respectively). There would be no change in the number of new FF [(fabric filter)] installs. Therefore, cost-effectiveness values for fPM and individual and total non-[mercury] HAP metals would only increase slightly.

89 Fed. Reg. at 38,521. According to EPA, then, accounting for a small compliance margin of only 20% would (1) increase the Rule's cost by approximately 70%, and (2) almost double the number of units that would have to upgrade their controls, at great cost. Proper consideration of this information could have resulted in a very different rulemaking.

Instead, without any analysis or explanation, EPA simply announces: "Therefore, cost-effectiveness values for fPM and individual and total non-[mercury] HAP metals would only increase slightly." *Id*. This conclusion does not follow from the sentences before it. This is not reasoned decision-making. EPA must, at a minimum, "identify the stepping stones to its final decision." *Costle*, 657 F.2d at 333. It must explain its reasons for the determinations it has made, not proclaim the outcome.

The Rule's cost effectiveness would be even more stark if EPA accounted for a 50% compliance margin, which its own record recognizes as the likely "target" rate, PM CEMS Memo at 2. EPA did not do that analysis, but it did consider an alternative, proposed standard of 0.060 lb/mmBtu, which is the equivalent of the final standard of 0.01 lb/mmBtu with a compliance margin of 40%. *See* 89 Fed. Reg. at 38,518. That analysis yielded a cost-effectiveness of $17,500,000/ton HAPs removed—about a 67% increase over EPA's cost-effectiveness with no compliance margin. 2024 Technical Memo at 16-17, Table 4.

EPA cannot ignore the real-world implications of its regulations. As the Supreme Court made clear, "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *State Farm*, 463 U.S. at 43 (quotation omitted). EPA has relevant data but refused to use them. EPA knows EGUs operate with a compliance margin but refused to account for one in its analysis. The Rule is arbitrary and capricious.

3. EPA's Failure to Account for the Shortened Life of the Vast Majority of Coal-Fired EGUs is Deeply Flawed.

The remaining useful life of a source subject to an EPA rule is a major determinant of whether that rule will be cost-effective. As EPA has explained:

> You treat the requirement to consider the source's "remaining useful life" … as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's Control Cost Manual require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs…. *Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations*.

66 Fed. Reg. 38,108, 38,126 (July 20, 2001) (emphasis added). Thus, the remaining useful life of a source can render the requirement for additional controls impossible to justify on a cost-effectiveness basis. That is the case here, but EPA refused to accept the facts.

Commenters noted the maximum life of the vast majority of coal-fired EGUs (after the effective date of this Rule) is just five years. RTC at 42-43. That is because EPA's recently promulgated rule to regulate greenhouse gases from EGUs makes retirement within about five years the only realistic option for most coal-fired plants. *See* 89 Fed. Reg. 39,798 (May 9, 2024)

("GHG Rule").[13] EPA turned a blind eye to this important fact and forged ahead with its unreasonable cost-effectiveness analysis.[14]

Instead, EPA assumed any unit without an announced retirement date has a life of 15 years and spread the capital cost of any control upgrades or new controls over that period. The resulting "capital charge rate," a measure of cost over time,[15] is 11.04%. 2024 Technical Memo, Attach. 1. But when the

---

[13] EPA's GHG Rule requires coal-fired EGUs to meet a carbon dioxide emission rate based on carbon, capture, and sequestration by January 1, 2032, and exempts from the GHG Rule any coal-fired EGU that agrees to permanently cease operation by that date. 89 Fed. Reg. at 39,801. For many reasons, this requirement is impossible for the vast majority of units, and they will have to retire and take the exemption to avoid violating the rule.

[14] *See also*, Talen & Northwestern Mot. For Stay, at 11-13 (EPA's failure to consider the interaction between this Rule and the GHG Rule arbitrary and capricious)

[15] A capital charge rate "is used to convert the capital cost into a stream of levelized annual payments that ensures capital recovery of an investment. The number of payments is equal to book life of the unit or the years of its book life included in the planning horizon (whichever is shorter)." EPA, *Documentation for EPA's Power Sector Modeling Platform v6 - Summer 2021 Reference Case*, at 10-12 (Sept. 20, 2021), https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.

unit's life is shortened due to the GHG Rule, the charge rate drastically increases.

For the Mayo plant, slated to be retired in 2031 according to EPA (approximately 5 years after the Rule becomes effective in 2027), the capital charge is 38.44%, *id.*, or 3.5 times that for a 15-year life.[16] Using EPA's assumptions, the cost-effectiveness for the Colstrip powerplant, for instance, is not about $16 million/ton of non-Hg metal HAPs removed, *see id*.; it would be 3.5 times more, or about $55 million/ton. That is a cost-effectiveness that is several times higher than levels EPA previously found not cost-effective. *See, e.g.*, Westmoreland Mot. For Stay, at 11&n.8.

This same cost multiplier applies to any unit that would have to upgrade its control to meet the standard (and as discussed above in Section I.B., there are many more units that will need upgraded controls than those

---

[16] According to EPA, Mayo would have to undertake an expensive ESP upgrade by 2027 before retiring in 2031. The resulting cost-effectiveness is an eye popping $76,775,000/ton of HAP removed. 2024 Technical Memo, Attach. 1.

identified by EPA). Ignoring reality is arbitrary and capricious. *See NRDC*, 808 F.3d at 574 (agency may not turn a blind eye to relevant facts).

For these reasons, Petitioners are likely to succeed on the merits.

II. The Balance of Harms and the Public Interest Weigh Heavily in Favor of a Stay.

A. Absent a Stay, the Rule Will Cause Irreparable Harm to Petitioners and Their Members.

Previous motions amply demonstrate the substantial, irreparable harm the industry will suffer if the Rule is not stayed. Some of the declarants in support of these motions are also members of Petitioners, and the harm they describe is the same as that for similarly situated EGUs. Petitioners adopt fellow Movants' arguments on irreparable harm to "avoid duplicative filings and repetitious arguments." Order 2, ECF#2062459.

B. A Stay Will Not Harm the Public

As discussed above in Section I.A, all of the coal-fired EGUs that would have to expend significant resources to install new controls or upgrade existing controls to meet the new fPM standard have cancer risks that are 1 to 3 orders of magnitude less than the 1-in1-million risk standard Congress put in the Clean Air Act and that is the gold standard for risk analysis.

Imposing the new standard on these units would not move the needle on risk. Indeed, shutting down every one of these units would avoid only one excess cancer case every 371 years. Considering that the stay would last no more than a few years, depending on how long this case takes to be resolved, there is absolutely no harm to the public from a stay.

C. The Public Interest Weighs in Favor of a Stay

A stay is in the public interest. If the Rule remains in effect during litigation, this will impose substantial costs on a handful of powerplants or could lead to their premature shutdown, while providing virtually no benefit to the general public or the environment relating to HAPs. Moreover, these costs—one way or the other—will end up being borne by the general public and the customers of the companies who operate these powerplants (e.g., through increased rates). Staying the Rule, on the other hand, will help to ensure the availability of reliable and affordable electricity.

Conclusion

For these reasons, this Court should stay EPA's Rule.

Dated: July 8, 2024

Respectfully submitted,

/s/ Makram B. Jaber
Makram B. Jaber
Allison D. Wood
Aaron M. Flynn
MCGUIRE WOODS LLP
888 16th Street N.W., Suite 500
Black Lives Matter Plaza
Washington, DC 20006
(202) 857-1700
mjaber@mcguirewoods.com
awood@mcguirewoods.com
aflynn@mcguirewoods.com

Counsel for Petitioners America's Power and Electric Generators MATS Coalition

Certificate of Compliance

Pursuant to Fed. R. App. P. 32(a)(5), (6) and D.C. Circuit Rules 27(a)(2), I certify that: This motion complies with the type-volume limitations of Fed. R. App. P. 27(d)(2)(A) because it contains 5,145 words, excluding the parts of the motion exempted by Fed. R. App. P. 32(f) and 27(a)(2)(B). This motion complies with the typeface and type style requirements of Fed. R. App. P. 27(d)(1)(E) because this brief has been prepared in a proportionately spaced typeface using Microsoft Word version 16.61 Palatino Linotype 14-point font.

/s/ Makram B. Jaber
Makram B. Jaber

CERTIFICATE OF SERVICE

I hereby certify that on this 8th day of July 2024, I filed the foregoing motion with the Clerk of the Court using the CM/ECF System, which will send notice of such filing to all registered CM/ECF users.

/s/ *Makram B. Jaber*
Makram B. Jaber

BAKER BOTTS L.L.P.

700 K STREET, N.W.
WASHINGTON, D.C.
20001

TEL +1 202.639.7700
FAX +1 202.639.7890
BakerBotts.com

AUSTIN
BRUSSELS
DALLAS
DUBAI
HOUSTON
LONDON
NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
SINGAPORE
WASHINGTON

July 17, 2024

Joshua B. Frank
TEL: 2026397748
FAX: 2025851021
joshua.frank@bakerbotts.com

<u>VIA CM/ECF</u>

Mark Langer, Clerk of Court
U.S. Court of Appeals for the D.C. Circuit
E. Barrett Prettyman U.S. Courthouse
and William B. Bryant Annex
333 Constitution Ave., NW
Washington, D.C. 20001

Re: Nos. 24-1190, 24-1217, 24-1194 (consolidated with No. 24-1119);
Talen Montana, LLC v. EPA; *NorthWestern Corp. v. EPA*;
Westmoreland Mining Holdings, LLC v. EPA

Dear Clerk Langer:

The undersigned Petitioners submit this letter to advise the Court of supplemental authority. *See* Fed. R. App. P. 28(j).

In *Loper Bright Enterprises v. Raimondo*, No. 22-451 (U.S. June 28, 2024), the U.S. Supreme Court held that "Courts must exercise their independent judgment in deciding whether an agency has acted within its statutory authority." Slip op. 35. An agency's judgment may be informative, but courts "may not defer to an agency interpretation of the law simply because a statute is ambiguous." *Id.* Even if the supposed ambiguity "happens to implicate a technical matter," courts must still determine and apply the "best reading of the statute." *Id.* at 23–25.

Loper Bright affects this case in at least two ways. First, EPA's interpretation that "new" information on the deployment of existing technology constitutes "developments" under Clean Air Act Section 112(d)(6) warrants no deference. *E.g.*, Talen Montana & NorthWestern Mot. 7–8. This Circuit has already interpreted that term to mean "innovations." *Id.* at 7 (citing *NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008)). Observing that facilities have more experience using the same control technologies does not satisfy EPA's statutory duty to "consider practical and technological advances." N.D. Mot. 6 (quoting *La. Env't Action Network v. EPA*, 955 F.3d 1088, 1098 (D.C. Cir. 2020)).

Second, EPA's interpretation that a rule is "necessary" even when the status quo "provides an ample margin of safety to protect public health" also warrants no deference. *E.g.*, *id.*; Westmoreland Mot. 10–16. Here too courts have already interpreted the term "necessary" to at least mean "required to achieve a desired goal." NRECA Mot. 16 (citing *GTE Serv. Corp. v. FCC*, 205 F.3d 416, 423 (D.C. Cir. 2000)). For Section 112(d)(6) specifically, EPA must also consider costs. *E.g.*, *id.* at 16–19 (citing *Michigan v. EPA*, 576 U.S. 743, 752–53 (2015)). EPA's determination that revising emission standards can be "necessary" with a "negative net monetized benefit" and no public health driver is not a "permissible" interpretation of the statute—much less the "best" one.

DATED: July 17, 2024

Respectfully submitted,

/s/ Joshua B. Frank

Joshua B. Frank
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street N.W.
Washington, D.C. 20001
Tel.: (202) 639-7748
(202) 639-1130
joshua.frank@bakerbotts.com
joshua.lee@bakerbotts.com

Counsel for Petitioner
Talen Montana, LLC

/s/ Michael Drysdale

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue N.W.,
Suite 900
Washington, D.C. 20005
Tel.: (202) 442-3555
magid.chip@dorsey.com

Michael Drysdale (*Of Counsel*)
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402
Tel.: (612) 340-5652
drysdale.michael@dorsey.com

Counsel for Petitioner
NorthWestern Corporation
d/b/a NorthWestern Energy

/s/ Mark W. DeLaquil

Mark W. DeLaquil
BAKER & HOSTETLER LLP
Suite 1100
1050 Connecticut Avenue, NW
Washington, D.C. 20036
Tel.: (202) 861-1527
mdelaquil@bakerlaw.com

Martin T. Booher
Joshua T. Wilson
BAKER & HOSTETLER LLP
2000 Key Tower
127 Public Square
Cleveland, Ohio 44114

Counsel for Petitioners
Westmoreland Mining Holdings,
LLC et al.

JF
cc: All counsel of record via CM/ECF

CERTIFICATEE OF COMPLIANCE

I certify that the forgoing document complies with the word limit set forth in Federal Rule of Appellate Procedure 28(j) because the body of the letter, inclusive of words found in footnotes, does not exceed 350 words.

DATED: July 17, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

CERTIFICATE OF SERVICE

I certify that on July 17, 2024, the foregoing document was served electronically on all registered counsel through the Court's CM/ECF system.

DATED: July 17, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

NOT YET SCHEDULED FOR ORAL ARGUMENT

No. 24-1119 and consolidated cases

U.S. COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

State of North Dakota, et al.,

Petitioners,

v.

U.S. Environmental Protection Agency,

Respondent.

Petitions for Review of a Final Rule of
the U.S. Environmental Protection Agency

EPA's Combined Opposition to Motions to Stay Final Rule

Todd Kim
Assistant Attorney General

Sue Chen
Redding Cofer Cates
U.S. Department of Justice
Environment & Natural Resources Div.
Environmental Defense Section
P.O. Box 7611
Washington, D.C. 20044
202.305.0283
sue.chen@usdoj.gov

Of counsel
Matthew McNerney
U.S. Environmental Protection Agency
Office of General Counsel
Washington, D.C.

CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

As required by D.C. Circuit Rule 27(a)(4), EPA certifies:

A. Parties and amici

Petitioners are:

- Case No. 24-1119: the State of North Dakota, State of West Virginia, State of Alaska, State of Arkansas, State of Georgia, State of Idaho, State of Indiana, State of Iowa, State of Kansas, Commonwealth of Kentucky, State of Louisiana, State of Mississippi, State of Missouri, State of Montana, State of Nebraska, State of Oklahoma, State of South Carolina, State of South Dakota, State of Tennessee, State of Texas, State of Utah, Commonwealth of Virginia, and State of Wyoming;
- Case No. 24-1154: NACCO Natural Resources Corporation;
- Case No. 24-1179: National Rural Electric Cooperative Association, Lignite Energy Council, National Mining Association, Minnkota Power Cooperative, Inc., East Kentucky Power Cooperative, Inc., Associated Electric Cooperative Inc., Basin Electric Power Cooperative, and Rainbow Energy Center, LLC;
- Case No. 24-1184: Oak Grove Management Company LLC and Luminant Generation Company LLC;
- Case No. 24-1190: Talen Montana, LLC;

- Case No. 24-1194: Westmoreland Mining Holdings LLC, Westmoreland Mining LLC, and Westmoreland Rosebud Mining LLC;
- Case No. 24-1201: America's Power and Electric Generators MATS Coalition;
- Case No. 24-1217: NorthWestern Corporation; and
- Case No 24-1223: Midwest Ozone Group.

Respondents are the U.S. Environmental Protection Agency and Michael S. Regan, Administrator.

Intervenor for Petitioners is San Miguel Electric Cooperative, Inc.

Intervenors for Respondent are Air Alliance Houston, Alliance of Nurses for Healthy Environments, American Academy of Pediatrics, American Lung Association, American Public Health Association, Chesapeake Climate Action Network, Citizens for Pennsylvania's Future, Clean Air Council, Clean Wisconsin, Downwinders at Risk, Environmental Defense Fund, Environmental Integrity Project, Montana Environmental Information Center, Natural Resources Council of Maine, Natural Resources Defense Council, the Ohio Environmental Council, Physicians for Social Responsibility, and Sierra Club; and the Commonwealth of Massachusetts, State of Minnesota, State of Connecticut, State of Illinois, State of Maine, State of Maryland, State of Michigan, State of New Jersey, State of New York, State of Oregon, Commonwealth of Pennsylvania, State of Rhode Island, State of Vermont, State of Wisconsin, District of Columbia, City of Baltimore, City of Chicago, and City of New York.

B. Rulings under review

Under review is EPA's action "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).

C. Related cases

No related case is or was before this or any other court.

<u>/s/ Sue Chen</u>
Counsel for EPA

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

*Authorities upon which we chiefly rely are marked with asterisks

Statutes

GLOSSARY

2023 Andover Report	Andover Technology Partners, Assessment of Potential Revisions to the Mercury and Air Toxics Standards (June 15, 2023), attached as Lassiter Decl. Ex. A
2023 Technology Memo	EPA, Memorandum on 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category (Jan. 2023), attached as Lassiter Decl. Ex. B
2024 Technical Memo	EPA, Memorandum on 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (Jan. 2024), attached as Lassiter Decl. Ex. C
2024 Technical Memo Att. 1	Attachment 1 to 2024 Technical Memo, attached as Lassiter Decl. Ex. D
2024 Technical Memo Att. 2	Attachment 2 to 2024 Technical Memo, attached as Lassiter Decl. Ex. E
Am. Power Mot.	Petitioners' Motion for Stay Pending Judicial Review (July 8, 2024) in Case No. 24-1201, filed by America's Power and Electric Generators MATS Coalition
Cichanowicz Report	J. Edward Cichanowicz et al., Technical Comments National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology (June 19, 2023), attached as Lassiter Decl. Ex. F
EPA	U.S. Environmental Protection Agency

lb/MMBtu	pounds per million British thermal units of heat input
lb/TBtu	pounds per trillion British thermal units of heat input
Lignite Council Comment	Comment from Lignite Energy Council (June 23, 2023), attached as Lassiter Decl. Ex. G
Midwest Ozone Mot.	Motion for Stay (July 8, 2024) filed by Midwest Ozone Group in Case No. 24-1223
PM CEMS Memo	EPA, Memorandum: PM CEMS Random Error Contribution by Emission Limit (Mar. 22, 2023), attached as Lassiter Decl. Ex. H
Reg. Impact Analysis	EPA, Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2024), attached as Lassiter Decl. Ex. I
Resource Adequacy Memo	EPA, Resources Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR: Technical Memo (Apr. 2024), attached as Lassiter Decl. Ex. J
Resp. to Comments	EPA, Summary of Public Comments and Responses on Proposed Rule (Apr. 2024), attached as Lassiter Decl. Ex. K
Rural Mot.	Petitioners' Motion for Stay of the Final Rule (June 21, 2024) in Case No. 24-1179, filed by National Rural Electric Cooperative Association et al.

Sargent & Lundy Report	Sargent & Lundy, PM Incremental Improvement Memo (Mar. 2023), attached as Lassiter Decl. Ex. L
States Mot.	Petitioners' Amended Motion for Stay (June 7, 2024) in Case No. 24-1119, filed by North Dakota et al.
Talen Mot.	Petitioner Talen Montana, LLC and Petitioner NorthWestern Corporation's Joint Motion for Stay (June 27, 2024) in Case Nos. 24-1190 and 24-1217
Westmoreland Mot.	Petitioner's Motion for Stay of the Final Rule (June 27, 2024) in Case No. 24-1194, filed by Westmoreland Mining Holdings LLC, Westmoreland Mining LLC, and Westmoreland Rosebud Mining LLC

INTRODUCTION

Congress's view on toxic air pollution is simple: Less is better. To that end, Congress decided that emission standards would be revised to reflect developments in emission-control practices, processes, and technologies.

The Clean Air Act's air-toxics program, 42 U.S.C. § 7412, embodies that approach. So does EPA's action here tightening two standards for power plants. Better and cheaper emission controls have made stricter standards feasible and their costs reasonable. So much so that almost all regulated entities can already meet those standards, while a small group of laggards emits an outsized share of toxic pollution. EPA, in line with Section 7412, thus reasonably adopted stricter standards.

Six sets of petitioners, in filings totaling over 2,400 pages, move to stay EPA's action. But quantity is not quality, and Movants offer no meritorious claim of a legal or record-based flaw in the standards. Nor can they show a clear and present need for the extraordinary relief they seek. The most that Movants can say is that the standards "may" (or may not) affect electricity grids, while the compliance date is three years away (with a one-year extension also available). That reticence confirms that there is no emergency to justify a stay. The Court should deny the motions.

BACKGROUND

I. A short history of Section 7412.

The Clean Air Act regulates emissions of hazardous air pollutants (or colloquially, air toxics) under 42 U.S.C. § 7412. These pollutants include neurotoxins like mercury, human carcinogens like arsenic and chromium, and a host of other toxic chemicals. *See id.* § 7412(b)(1)-(2); 89 Fed. Reg. 38508, 38515/2-3 (May 7, 2024).

Section 7412 began as a risk-based program. Under that regime, EPA had to assess a pollutant's risk before setting emission limits. *See Sierra Club v. EPA*, 353 F.3d 976, 979 (D.C. Cir. 2004). That approach proved "disappointing" because risk analysis was hard and slow going. *Id.*; *see* 89 Fed. Reg. at 38513/3. It took EPA 20 years to regulate just 7 air toxics. 89 Fed. Reg. at 38514/1.

Frustrated with EPA's sluggish pace in curbing air-toxics emissions, Congress in 1990 revamped Section 7412, transforming it into a technology-driven regime. *Sierra Club*, 353 F.3d at 979-80. The new regime, designed to swiftly slash emissions based on what is technologically achievable, uses a two-phase regulatory process. 89 Fed. Reg. at 38513/2.

In phase one, EPA sets emission standards for categories of sources that emit air toxics. 42 U.S.C. § 7412(d). The standards, based on maximum achievable control technologies rather than risk, are set by examining what the best-performing 12 percent of existing sources can do. *Id.* § 7412(d)(3). These standards (dubbed the "MACT floor") serve as the stringency floor.

EPA can go beyond that floor and set stricter standards if they are "achievable." *Id.* § 7412(d)(2). In this analysis, EPA considers "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements…." *Id.* Once EPA sets initial emission standards (be it the floor or beyond the floor), phase one ends.

Phase two entails reviewing existing standards. Section 7412 requires two reviews that proceed on "distinct, parallel" tracks. *Nat'l Ass'n for Surface Finishing v. EPA*, 795 F.3d 1, 5 (D.C. Cir. 2015). The first is a risk review, required within eight years after standards are promulgated for a source category. 42 U.S.C. § 7412(f)(2)(A). In the risk review, EPA considers whether the standards provide "an ample margin of safety" to protect public health and the environment. *Id*. If they do not, EPA must tighten the standards. *Id.*; *see Surface Finishing*, 795 F.3d at 5. Section 7412(f)(2), however, does not require EPA to eliminate all risk to public health and the environment.

The other review—at issue here—is a technology review. This is a recurring review that happens at least every eight years. 42 U.S.C. § 7412(d)(6). In the technology review, EPA considers "developments in practices, processes, and control technologies" and "revise[s the standards] as necessary." *Id.* Because technology reviews necessarily contemplate going beyond the floor, EPA also looks to factors enumerated in Section 7412(d)(2) to determine whether stricter standards are achievable. *See* 89 Fed. Reg. at 38531/1 (explaining that technology reviews consider "costs, technical feasibility, and other factors").

II. Regulating air-toxics emissions from power plants.

Coal- and oil-fired power plants are among the largest domestic emitters of mercury, arsenic, chromium, lead, and other air toxics. *Id.* at 38509/3. In 2012 EPA found that it was "appropriate and necessary" to regulate air-toxics emissions from coal- and oil-fired electric utility steam-generating units (that is, power plants), and promulgated standards to do so. 77 Fed. Reg. 9304 (Feb. 16, 2012); 42 U.S.C. § 7412(n)(1)(A); 40 C.F.R. Part 63, subpart UUUUU.

This Court upheld the 2012 rule. *See White Stallion Energy Ctr. LLC v. EPA*, 748 F.3d 1222, 1247-51 (D.C. Cir. 2014) (per curiam). On petitions for certiorari, the Supreme Court limited review to the threshold issue of whether EPA had to consider costs in its "appropriate and necessary" finding. *Michigan v. EPA*, 576 U.S. 743 (2015). Because EPA did not do so, the Supreme Court reversed this Court's judgment. *Id.* at 760. The Supreme Court never opined on the 2012 standards themselves, and this Court remanded the rule to EPA while leaving those standards in place. Order, *White Stallion*, Case No. 12-1100 (D.C. Cir. Dec. 15, 2015).

On remand, EPA completed supplemental "appropriate and necessary" findings that address costs. 81 Fed. Reg. 24420 (Apr. 25, 2016); *see* 88 Fed. Reg. 13956, 13962/1-3 (Mar. 6, 2023) (summarizing administrative history). Most recently, in 2023 EPA considered costs and found that it is appropriate and necessary to regulate air-toxics emissions from coal- and oil-fired power plants. 88 Fed. Reg. at 13956/1. No one challenged that finding.

Meanwhile, in 2020, EPA completed its risk review and first technology review. 85 Fed. Reg. 31286 (May 22, 2020). In the risk review, EPA concluded that the 2012 standards provided an ample margin of safety and thus need not be revised. *Id.* at 31314/3. In the technology review, EPA found no developments in practices, processes, or control technologies to warrant revision. *Id.*

III. The 2024 rule.

In 2024, EPA reviewed the 2020 action. 89 Fed. Reg. at 38508/1. It did not reopen the 2020 risk review. *Id.* at 38518/1-2. But EPA disagreed with the 2020 technology review: It determined there are developments in practices, processes, and control technologies that warrant revising the 2012 standards. *Id.* at 38518/3. Although the fundamental nature of emission-control technologies had not changed since 2012, better practices, along with technical and operational improvements, made those controls more efficient and cheaper to use. *Id.* at 38530/1-2, 38537/3;

see id. at 38541/3 (noting that the 2020 review did not address these developments).

Movants focus on two standards that EPA revised for coal-fired units:

Surrogate standard for non-mercury metals: The 2012 rule set emission standards for non-mercury metals like arsenic, chromium, and lead. *Id.* at 38510/1 & n.2. It also gave regulated entities the option to use a surrogate standard based on filterable particulate matter, the control of which also reduces non-mercury metals. *Id.* at 38510/1. Almost all coal-fired units chose to use the surrogate standard in lieu of the metals standards. *Id.* In the 2024 rule, EPA tightened the surrogate standard to a level that almost 90 percent of coal-fired units could already meet. *Id.* at 38510/1, 38524/3. The stricter standard would thus bring the stragglers in line with the rest of the industry.

Mercury standard for lignite units: Lignite coal, mined mostly in North Dakota and Texas, ranks lowest among all coals in terms of quality because it has the lowest energy content. 2024 Technical Memo 37. In 2021, lignite accounted for only about 8 percent of domestic coal production. *Id*. By contrast, bituminous and subbituminous coal, both ranked higher than lignite, together accounted for over 90 percent. *Id.*

The 2012 rule set two mercury standards, one for units burning lignite coal, and a stricter standard for units burning all other types of coal. 77 Fed. Reg. 9304, 9367 (table 3) (Feb. 16, 2012); 89 Fed. Reg. at 38537/2. In the 2024 rule, EPA determined that cost-effective controls are available for lignite units to meet the same mercury limit that has applied to other coal-fired units, and it tightened the standard for lignite units accordingly. 89 Fed. Reg. at 38537/3-49/2.

* * *

The rule took effect on July 8, 2024. *Id.* at 38508/1. Power plants have three years, until July 2027, to comply, and their permitting authorities can grant a one-year extension when necessary. *Id.* at 38519/3.

IV. Procedural history.

States, power plants, mining companies, and others filed nine petitions for review of the 2024 rule. Six stay motions followed. States Mot. (June 7, 2024); Rural Mot. (June 21, 2024); Talen Mot. (June 27, 2024); Westmoreland Mot. (June 27, 2024); Midwest Ozone Mot. (July 8, 2024); Am. Power Mot. (July 8, 2024); *see* Petitioner NACCO Natural Resources Corp.'s Joinder in the State Petitioners' Motion for Stay (June 14, 2024). The Court granted EPA's request to file a consolidated response. Order (July 1, 2024).

STANDARD OF REVIEW

"On a motion for stay, it is the movant's obligation to justify the court's exercise of such an extraordinary remedy." *Cuomo v. U.S. Nuclear Regul. Comm'n*, 772 F.2d 972, 978 (D.C. Cir. 1985) (per curiam), *abrogated on other* *grounds by Winter v. NRDC*, 555 U.S. 7 (2008). Movants must show (1) a likelihood of success on the merits; (2) irreparable injury to them if relief is denied; (3) lack of substantial harm to others; and (4) where the public interest lies. *Nken v. Holder*, 556 U.S. 418, 434 (2009). The last two criteria merge here. *Id.* at 435.

On the merits, the disputed standards are reviewed under the same arbitrary-and-capricious standard as under the Administrative Procedure Act. *See* 42 U.S.C. § 7607(d)(9)(A); *Miss. Comm'n on Env't Quality v. EPA*, 790 F.3d 138, 150 (D.C. Cir. 2015) (per curiam). The review is a "narrow" one and "a court is not to substitute its judgment for that of the agency." *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *see also Loper Bright Enters. v. Raimondo*, 144 S. Ct. 2244, 2261 (2024) ("Section 706 [of the Administrative Procedure Act] does mandate that judicial review of agency policymaking and factfinding be deferential." (emphasis omitted)). The Court should uphold a decision when the agency considered the relevant factors and articulated a rational connection between the facts found and the choices made. *State Farm*, 463 U.S. at 43. That is true even when the decision has "less than ideal clarity" so long as "the agency's path may reasonably be discerned." *Id.* (internal quotation marks omitted).

Finally, an agency's "interpretations and opinions," made in pursuance of official duty and based on special experience, constitute a "'body of experience and informed judgment to which courts and litigants could properly resort for guidance,' even on legal questions." *Loper Bright*, 144 S. Ct. at 2259 (quoting *Skidmore v. Swift & Co.*, 323 U.S. 134, 139-40 (1944) (internal brackets omitted)).

ARGUMENT

No stay should issue. Movants have not shown a likelihood of success on the merits. Nor do they have "strong arguments about the harms they face and equities involved." *Ohio v. EPA*, 144 S. Ct. 2040, 2053 (2024). To the contrary, Movants' claims of irreparable harm lack evidence and the equities disfavor a stay.

I. Movants are unlikely to succeed on the merits.

Movants are unlikely to prevail on the merits. First, their reading of Section 7412 clashes with circuit precedent, not to mention statutory text and design. Second, their record-based arguments ignore much of the record. Third, though Movants accuse EPA of improper motive in the rulemaking, the record belies that fiction. Finally, Movants' arguments as to the Colstrip facility flout Section 7412.

A. The technology review complies with Section 7412(d)(6).

1. "Developments" in practices, processes, and technology include improvements in those areas.

Section 7412(d)(6) requires EPA to revise existing emission standards as necessary, "taking into account developments in practices, processes, and control technologies." In the 2024 rule, EPA identified a "clear trend in control efficiency, costs, and technological improvements" since 2012—a trend that the 2020 technology review overlooked. 89 Fed. Reg. at 38521/1, 38541/3; *contra* Rural Mot. 18. These improvements include more durable filter-bag material, better monitoring practices, and the development of sulfur-resistant chemicals designed to capture mercury from bituminous and lignite coals. 89 Fed. Reg. at 38521/1, 38530/2, 38541/3. All these changes improved how effectively coal-fired units can reduce their air-toxics emissions. Partly due to those improvements, meeting the 2012 standards costs less money than expected. *Id.* at 38530/1.

Movants' contention that no "development" occurred runs aground on the facts and the law. On the facts, Movants either overlook new products (like sulfur-resistant chemicals) or downplay other advances. *E.g.*, States Mot. 7; Rural Mot. 9-11; Talen Mot. 6-10; Westmoreland Mot. 17-18. But dismissing improvements as trivial does not make them so. For example, more durable filter bags lower both the risk that a control might fail, and the wear and tear that impairs efficacy. 89 Fed. Reg. at 38530/2; *contra* Westmoreland Mot. 17-18. That is a meaningful improvement. It is unclear what kind of "validat[ion]" Movants demand, for Section 7412(d)(6) does not require EPA to "quantify" improved efficacy. Talen Mot. 8.

At bottom, Movants' dismissive attitude is rooted in a misunderstanding of the law. "Developments," Movants urge, means changes that are both "*new* and *significant*." Westmoreland Mot. 16. On that view, in technology reviews EPA can consider only practices, processes, and technologies that differ fundamentally from what came before. *See* Rural Mot. 9-11; States Mot. 6-7; Talen Mot. 6-10. But that is not what Section 7412(d)(6) says. "Developments," in its ordinary usage, means "the act, process, or result of developing," which in turn means "to cause to evolve or unfold gradually." *See* "Development" and "Developing," Merriam-Webster;[1] Talen Mot. 7 (offering similar definition). The statute thus encompasses incremental changes over time. And that is how progress happens in the real world, where true overnight revolutions in technology are rare; much more common are modest changes that gradually but meaningfully improve the status quo.

This Court rejected Movants' view years ago in *Surface Finishing*. Though petitioners there did not directly challenge the meaning of "developments," they argued that EPA had failed to identify specific developments that warranted revising standards. 795 F.3d at 11. The Court disagreed, holding that EPA permissibly accounted for developments under Section 7412(d)(6)—developments that, as interpreted by EPA, covered "not only wholly new methods," but also "technological improvements," "improvements in efficiency," and "reduced costs." *Id.* (internal quotation marks omitted). In so holding, the Court necessarily agreed

[1] *Available at* https://perma.cc/K9LL-9SQP; https://perma.cc/2TE7-GNUB.

with EPA's reading of "developments" to include technologies that, though "not brand new," underwent "improvements [that] resulted in emissions reductions." *Id.*; *contra* Talen Mot. 7. The improvements identified in the 2024 rule—longer-lasting filter bags, new chemicals to control mercury emissions, improved processes—fall squarely within the kind of developments this Court recognizes as valid under Section 7412(d)(6).[2] *See* 89 Fed. Reg. at 38521/1-2.

To be sure, *Surface Finishing* applied the *Chevron* framework, which the Supreme Court recently overruled. *Loper Bright*, 144 S. Ct. at 2273; *see* 795 F.3d at 7. But *Loper Bright* did "not call into question prior cases that relied on the *Chevron* framework" despite the "change in interpretive methodology." 144 S. Ct. at 2273. So *Surface Finishing*'s holding that EPA's action was lawful remains good law. *Cf.* Talen 28(j) Letter (July 17, 2024) (advising Court of *Loper Bright*).

---

[2] In *NRDC v. EPA*, this Court did not rewrite the statute by reading "developments" to mean only "technological improvements." 529 F.3d 1077 (D.C. Cir. 2008); *contra* States Mot. 7; Talen Mot. 7; Westmoreland Mot. 18; Talen 28(j) Letter 1-2. There, the Court said that technology reviews do not involve resetting the MACT floor. 529 F.3d at 1084. But even if they did, the Court added, petitioners had not identified any "technological innovations" overlooked by EPA. *Id.* The Court never purported to interpret "developments."

And the 2024 rule did not reset MACT floors. *Contra* Rural Mot. 11. That process entails analyzing what the best-performing 12 percent of existing sources can do. 42 U.S.C. § 7412(d)(3). EPA analyzed almost all sources here. *See* 2024 Technical Memo 9, 28; 89 Fed Reg. at 38553/3 & n.88 (noting that EPA lacked relevant data for only about 6 percent of coal-fired units).

EPA's—and the Court's—reading of "developments" aligns not only with statutory text, but also statutory design. Congress rewrote Section 7412 as a technology-based regime. Whereas it ordered a one-time risk review, Congress specified that technology reviews recur at least every eight years. The goal is to ensure that, over time, EPA maintains standards that are "on pace with emerging developments that create opportunities to do even better." *La. Env't Action Network v. EPA*, 955 F.3d 1088, 1093 (D.C. Cir. 2020) (*LEAN*). Congress, in other words, wanted to keep reducing air-toxics emissions when technology allows. 89 Fed. Reg. at 38514/3. It would stymie congressional intent to ignore incremental advances that fall short of being "brand-new." Rural Mot. 10-11; *see* States Mot. 7; Talen Mot. 7-10; Westmoreland Mot. 16.

2. Section 7412 directs the technology review to proceed independently of the risk review.

Also meritless is Movants' insistence that EPA cannot tighten standards found to have an ample margin of safety in the risk review. *E.g.*, Am. Power Mot. 5-9; Midwest Ozone Mot. 5; States Mot. 6, 8; Rural Mot. 17-18; Talen 28(j) Letter 2. Once again, Movants overlook statutory text and design.

Section 7412 imposes separate and distinct requirements on risk and technology reviews. *Surface Finishing*, 795 F.3d at 5. The risk review asks whether, given currently available information, existing standards offer an ample margin of safety to protect public health and the environment. 42 U.S.C.

§ 7412(f)(2). It also directs EPA to require that margin within eight years of promulgating the original standards. *Id.*

In contrast, the technology review asks—on a recurring basis—whether advances in emission controls warrant stricter standards. *Id.* § 7412(d)(6). It applies to all standards, including those that provide ample margins of safety. Congress, in other words, wanted EPA to consider tightening standards based on developments in controls even after safety margins are in place. Otherwise, it would not have required the technology review to recur once the risk review was complete. Nor does Section 7412(d)(6) require technology reviews to account for safety margins or health and environmental risks. *See Ass'n of Battery Recyclers v. EPA*, 716 F.3d 667, 672 (D.C. Cir. 2013) (per curiam) ("[N]othing in section [74]12(d)(6)'s text suggests that EPA must consider" public-health factors); 89 Fed. Reg. at 38525/2-3.[3] Rather, technology reviews consider factors like feasibility and costs. *See* 89 Fed. Reg. at 38531/1.

This setup reflects Congress's decision that technological progress should drive the regulation of air toxics independent of EPA's risk assessment. *Id.* at

[3] EPA often tightens Section 7412 standards with ample margins of safety. *See* 89 Fed. Reg. at 38525 n.29 (giving examples). So what it did here was not a "change of position." Rural Mot. 18. Granted, EPA has, in its discretion, considered risk during technology reviews. States Mot. 4 (citing 69 Fed. Reg. 48338 (Aug. 9, 2004); 71 Fed. Reg. 76603 (Dec. 21, 2006)); Westmoreland Mot. 13. But as the agency noted on one such occasion, an ample margin of safety does not bar tightening standards under Section 7412(d)(6). 71 Fed. Reg. at 76609/2.

38525/3. After all, in revamping Section 7412, Congress made clear that air-toxics emissions are inherently dangerous and sought to reduce those emissions as much as achievable using technology. *Id.* at 38513/3-14/3. And the reality is that scientific advances and newly available data sometimes show that things we had thought "safe" are in fact risky. *See, e.g.*, 73 Fed. Reg. 66964, 66975/2 (Nov. 12, 2008) (updating air-quality standards for lead based on new evidence of neurotoxicity at low doses). In choosing technology-based standards, Congress declined to tether the air-toxics program to risk assessments that could become outdated.

Further, an "ample margin of safety" determination does not mean zero risk. *Contra* States Mot. 1, 6, 10; Rural Mot. 17-18; Talen Mot. 14-15; Westmoreland Mot. 12-13. Coal-fired units emit air toxics that cause serious health problems. Though risks are now much lower, they still exist—and these risks mattered to Congress. 89 Fed. Reg. at 38556/3, 38541/3; *see id.* at 38524/3 (noting disparity in exposure to nearby communities from well-controlled sources versus other sources); Reg. Impact Analysis 4-5, 4-7. That is why Congress directed EPA to continue to require achievable reductions in air-toxics emissions as much as possible, even when standards offer an ample margin of safety.

B. The technology review is sound.

1. EPA reasonably considered feasibility and costs.

EPA considers "costs, technical feasibility, and other factors when evaluating whether it is necessary to revise existing emission standards under [Section 7412](d)(6) to ensure the standards 'require the maximum degree of emission reductions…achievable.'" 89 Fed. Reg. at 38531/1 (quoting 42 U.S.C. § 7412(d)(2)). Here, deference is due EPA's reasonable conclusion that the two challenged standards are achievable given its consideration of those factors.

a. Surrogate standard.

The rule lowered the surrogate standard for non-mercury metals from 0.030 lb/MMBtu to 0.010 lb/MMBtu, measured on a rolling-average basis. *Id.* at 38510/2 & n.4, 38566/1. This new standard is achievable because it is feasible and its costs are reasonable. *See id.* at 38531/1. At a minimum, EPA acted reasonably in so concluding.

The standard is feasible because almost all coal-fired units showed that they could already meet it. *Id.* at 38530/1-3. In this analysis, EPA considered the units' ability to emit at or below 0.010 lb/MMBtu, and to do so over time.

First, quarterly emissions data showed that even before EPA proposed 0.010 lb/MMBtu as a standard, most coal-fired units could achieve that level. The data covers 275 out of 314 coal-fired units. 2023 Technology Memo 2; 2024 Technical

Memo 8; 89 Fed. Reg. at 38553/3. Because electricity demand—and thus emissions—peaks in winter and summer, EPA focused on data from those quarters. 2024 Technical Memo 3; Resp. to Comments 24; *cf.* Rural Mot. 14-15 (quoting *White Stallion*, 748 F.3d at 1251, to argue that "achievable" means "capable of being met under most adverse conditions which can reasonably be expected to recur"); *contra id.* at 12 (misstating that EPA reviewed data "from quarters with the lowest emission rates"); Am. Power Mot. 9-10. The winter and summer data showed that 91 percent of the units achieved emission rates of 0.010 lb/MMBtu or less. 89 Fed. Reg. at 38530/2; 2023 Technology Memo 4-8.

Then, in response to comments, EPA also considered data from other quarters. 89 Fed. Reg. at 38530/2. It reviewed all quarterly emissions data it had for 62 coal-fired units. *Id.* This review, which accounts for the lower-emitting seasons of spring and autumn, found that an even greater percentage of units—93 percent—achieved 0.010 lb/MMBtu or less. *Id.*

Second, EPA considered average emission rates at 296 coal-fired units. 2024 Technical Memo 9. Because emission rates can vary, it is important to consider average rates, which show a unit's ability to emit at 0.010 lb/MMBtu on a sustained basis. *See* Resp. to Comments 30-31 (noting that average rates account for unit variability); *cf.* Am. Power Mot. 9-17 (sidestepping this analysis); Rural Mot. 12-13 (same). The data showed that 263 units (or 89 percent) can consistently achieve that level of control. 89 Fed. Reg. at 38530/3, 38533/3; *see id.* at 38522/1 (noting that Movant National Rural Electric Cooperative Association's estimate came close); 2024 Technical Memo 17 & Att. 2; *contra* Am. Power Mot. 15-16. Indeed, the median of the average rates was only 0.004 lb/MMBtu. 89 Fed. Reg. at 38522/1. Even among the 33 units (11 percent) that did not average 0.010 lb/MMBtu or less, more than half achieved that level at some point. *See* 2024 Technical Memo Att. 1 at 50-51 (column F).

Given that almost all regulated units could, with existing technology, consistently emit at or below 0.010 lb/MMBtu, EPA reasonably set the surrogate standard at that level. Of course, among units that averaged 0.010 lb/MMBtu or less, emissions at times exceeded that level. *See* Am. Power Mot. at 12-15 (spotlighting Coronado facility); Resp. to Comments 25 (noting that Coronado's rolling-average emissions were at or below 0.010 lb/MMBtu about 70 percent of the time). Those higher levels are unsurprising because they happened when the standard was still 0.030 lb/MMBtu. There was nothing special about 0.010 lb/MMBtu then, and one would not expect regulated units to try to keep their emissions below that level. *See* Resp. to Comments 36; 89 Fed. Reg. at 38510/1 n.3. So the sporadic higher levels do not alter either the fact that regulated units could, using existing controls, average 0.010 lb/MMBtu, or the conclusion that the 0.010 lb/MMBtu standard is feasible. *Contra* Am. Power Mot. 15-16.

EPA also explained why the standard's compliance costs are reasonable. 89 Fed. Reg. at 38533/1-34/1. First, even before EPA adopted the new standard, almost all coal-fired units had invested in the necessary emission controls to meet it. *Id.* at 38533/3. Had costs been unreasonable, those investments would not have happened. Second, compliance costs are only 0.03 percent of coal-fired units' revenue. *Id.* at 38533/2. Third, EPA accounted for factors that skewed its cost estimate: Two units at the Colstrip facility in Montana are the only coal-fired units in the country without modern emission controls. *Id.* at 38533/3. To meet the standard, those two would have to install better controls. *Id.* The cost of their upgrades accounts for over 40 percent of total annual costs. *Id.*[4] At the same time, of the 33 units that would incur compliance costs, 20 account for only 1 percent of total annual costs. *Id.* at 38533/3-34/1; *see* Resp. to Comments 31, 37; 2024 Technical Memo 15; *contra* Am. Power Mot. 11-12. So for most of the affected units, EPA's annual-cost estimates greatly overstate their actual costs.

Some Movants focus on the surrogate standard's cost-effectiveness (meaning the cost per ton or pound of pollution reduction). *E.g.*, States Mot. 10. That figure, they say, far exceeds what EPA had rejected for other air-toxics standards in industries as disparate as petroleum refining, iron-ore processing, and

[4] EPA assumed that Colstrip would install fabric filters. 2023 Technology Memo 9. Filter-bag vendors have "historically offered…guarantees [of emission rates] at 0.010 lb/MMBtu." Sargent & Lundy Report 2, 9; *contra* Talen Mot. 18.

portland-cement manufacturing. *Id.*; Westmoreland Mot. 10-12; *see* 89 Fed. Reg. at 38522/2-3. Yet what it reasonably costs to reduce a pound of pollutants in one industry may be unreasonable in a very different industry. 89 Fed. Reg. at 38523/3-24/3.[5] Cost-effectiveness is also just one metric that EPA considers alongside many others. *Id.* at 38523/3-24/1. Those other metrics here—the broad adoption of necessary controls, the modest cost-to-revenue ratio, and the skewed cost estimate toward one high-emitting facility—show that EPA reasonably imposed costs on a small group of coal-fired units so they can catch up to everyone else. *Id.* at 38530/3.

In calculating cost-effectiveness, EPA also properly declined to assume that most coal-fired units would retire soon. *Contra* Am. Power Mot. 22-26. Though Movants predict that EPA's recently finalized greenhouse-gas rule (a separate action not at issue here) would lead coal-fired units to retire in five years, *id.* at 23-24, nothing in that rule compels retirement. *See* Respondents' Opp. to Mots. to Stay Final Rule, *West Virginia v. EPA*, Case No. 24-1120 and consolidated cases

[5] There is no inconsistency in how EPA distinguished petroleum refineries from power plants. *Contra* Westmoreland Mot. 16. In the petroleum-refineries review, two high-performing sources used existing technologies. After considering the cost-effectiveness of tightening the applicable standard, EPA decided against setting a standard for the industry based on only two high performers. 80 Fed. Reg. 75178, 75201/1-2 (Dec. 1, 2015); 89 Fed. Reg. at 38524/1-2. By contrast, here almost the entire industry performed well. EPA did not claim, as Movants seem to imply, to use different approaches in estimating cost-effectiveness in the two rules. The difference follows from different context in the two industries.

(D.C. Cir. June 11, 2024), Argument § I.B. It instead requires states to develop plans that establish feasible technology-based greenhouse-gas emission standards for coal-fired power plants that do not intend to retire by January 1, 2032. *See* 89 Fed. Reg. 39798, 39840/2-902/3 (May 9, 2024).

To support their retirement argument, Movants cite proposed guidelines that address the Clean Air Act's regional-haze program. *See* Am. Power Mot. 23 (citing 66 Fed. Reg. 38108, 38126 (July 20, 2001)); 66 Fed. Reg. at 38108/1; 42 U.S.C. § 7491. Those guidelines do not apply to this air-toxics dispute. In any event, they do not require accounting for hypothetical retirement dates when calculating costs. *See* 66 Fed. Reg. at 38126/2 (basing "remaining useful life" assessment on closing date that "must be assured by a federally-enforceable restriction preventing further operation"); 40 C.F.R. Part 51, App. Y. § IV.D.4.k (final guidelines). So that document is not evidence of arbitrary action.

Nor did EPA err in calculating cost-effectiveness for Colstrip. *Contra* Talen Mot. 18. EPA estimated that fabric filters can slash Colstrip's emissions by 90 percent, to just above 0.002 lb/MMBtu. 2023 Technology Memo 10. That reduction amount was used to calculate cost-effectiveness. *Id.* at 9-10. Movants, however, act as if fabric filters can reduce Colstrip's emissions to 0.010 lb/MMBtu and no more. Talen Mot. 18. But fabric filters cannot be easily fine-tuned to reduce pollutants by a specified amount and stop there. So Movants' method, in undercounting the amount of reduced pollution, distorts cost-effectiveness (and omits the compliance margin they urge elsewhere). *See* Am. Power Mot. 17-20; Rural Mot. 13. EPA also reasonably declined to assume that Colstrip would retire soon when Colstrip itself had not—and apparently still has not—decided to retire. *Contra* Talen Mot. 18-19; *see* Lebsack Decl.

Movants' other arguments are easily refuted. First, in the feasibility analysis, EPA properly considered units that use both coal and natural gas. *Contra* Rural Mot. 12-13. EPA's goal is to evaluate the performance of units that would be subject to the surrogate standard. That includes coal-fired units that also burn natural gas. *See* 2023 Technology Memo 5-6 (table 1). Indeed, one control strategy for coal-fired units is to use some natural gas. *Cf.* 89 Fed. Reg. at 38538/3 (explaining this in context of mercury standard). Because EPA considered emissions data from units that use emission controls, for consistency it was reasonable to consider emissions from coal-fired units that also use natural gas. *Id.*

Second, citing a report they commissioned, Movants decry EPA's supposed underestimate of control-retrofit costs by 50 percent and say that annual costs are $1.96 billion. *See* Rural Mot. at 13 (citing Cichanowicz Report at 21). In reality, the report estimated those costs for a standard of 0.006 lb/MMBtu—much lower than what EPA finalized. *See* Cichanowicz Report at 21 ("To meet the alternative PM rate of 0.006 lb/MMBtu, 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").

Finally, the surrogate standard accounts for compliance margins. *Contra* Am. Power Mot. 17-20; Rural Mot. 13. Power plants often target emission levels below what standards require. 89 Fed. Reg. at 38521/3. Doing so creates a margin for error in case their equipment malfunctions or breaks down. *Id*. That margin is baked into the standard in two ways.

One is by setting the emission limit above what most coal-fired units were emitting on average. Recall that EPA considered average emission rates of 296 coal-fired units. 2024 Technical Memo 9. Averages account for operational variability and degradation of emission controls over time. Resp. to Comments 31. In this way, averages capture the kind of equipment problems and variabilities that regulated units must normally contend with. In fact, most of the 296 units in EPA's analysis averaged well below 0.010 lb/MMBtu: The median emission rate was only 0.004 lb/MMBtu, 60 percent below the new standard. 89 Fed. Reg. at 38522/1. This difference—between what most regulated units can do and what the standard requires them to do—serves as a built-in compliance margin that accounts for most causes of emission spikes.

The other place that the standard builds in a margin is on the compliance side. It assesses a given facility's compliance using 30-day rolling averages:

Compliance on any day is based on the facility's average emissions over the last 30 days when fuel was combusted. *See id.* at 38566/1. Rolling averages dampen isolated emission spikes. *Cf. id.* at 38544 (Figure 1) (illustrating this effect for mercury standards). That in turn gives regulated entities a flexibility that allows for normal hiccups in operations.

Movants are thus wrong that EPA ignored compliance margins. Am. Power Mot. 17-20. The surrogate standard accounts for those margins along the same lines that EPA did in Movants' examples, by factoring in variability and allowing compliance flexibility. *See id.* at 18.[6] And because the surrogate standard in effect has a built-in compliance margin, that margin's cost was necessarily part of EPA's cost analysis. *Contra id.* at 18-22; Rural Mot. 13; *see* 89 Fed. Reg. at 38522/1.[7]

b. Mercury standard.

The rule also lowered the mercury standard for lignite units from 4.0 lb/TBtu to 1.2 lb/TBtu, the limit that has applied to every other coal-fired unit since 2012. 89 Fed. Reg. at 38518/3. In the 2012 rule, EPA treated lignite units differently, but

---

[6] EPA declined to pick a specific compliance margin because power plants have different compliance strategies and thus different preferred compliance margins. *See* 89 Fed. Reg. at 38521/3; Am. Power Mot. 19-20. Movants are wrong that a specific compliance margin is mandated by an EPA memorandum about proper instrument calibration. *See* Am. Power Mot. 19 (citing PM CEMS Memo).

[7] EPA did a sensitivity analysis that considered a 20 percent compliance margin. 89 Fed. Reg. at 38521/3. But because that analysis would have not changed EPA's decision to tighten the surrogate standard, *id.*, Movants' emphasis of it misses the point. Am. Power Mot. 20-22.

not based on any unique property of lignite. Rather, limited data showed that lignite-fired units were not among the best performers. 89 Fed. Reg. at 38541/1-2. In the 2024 rule, however, EPA saw that cost-effective controls are available to lignite units. *Id.* at 38537/2-49/2. The record thus supports EPA's conclusion that the stricter standard is feasible and its costs reasonable for lignite units. *Id.* at 38541/3. Again, EPA acted reasonably.

Start with feasibility. EPA considered both commercially available mercury controls and emission levels that lignite units have actually achieved. As background, when coal burns, it releases mercury in the elemental state. Elemental mercury, however, cannot be captured by controls, be they fabric filters or electrostatic precipitators. To be captured, elemental mercury must first be oxidized, typically by halogens, a group of elements that includes chlorine and bromine. *See* 89 Fed. Reg. at 38539/1; 88 Fed. Reg. 24854, 24875/1 (Apr. 24, 2023). Chemical powders (usually made of carbon and called "sorbents") are then injected into coal-combustion flue gas, where they bind to the oxidized mercury, allowing it to be captured and removed. 89 Fed. Reg. at 38540/2. Controlling mercury from coal with low halogen content, like lignite, is thus harder.

Harder, but still feasible: Subbituminous coal's halogen content is comparable to lignite's, and subbituminous units have long been complying with the 1.2 lb/TBtu limit, often emitting at "considerably lower" levels. *Id.* at 38539/1-

2 (noting that high alkalinity in subbituminous and lignite coals exacerbates effects of low halogen content); *see id.* at 38543 (tables 5-6). They have done so by injecting additional halogens (via brominated sorbents) into flue gas. *Id.* at 38545/3. Subbituminous units' success shows it is feasible to capture mercury from low-halogen coal like lignite. *Id.* at 38539/1-2, 38545/3-46/1.

Other characteristics of lignite coal—higher sulfur content, and higher and variable mercury content—can also make it hard to control mercury emissions. *Id.* at 38541/1. But as with halogen content, these characteristics are also found in other types of coal. *Id.* at 38541/2. Some bituminous coals have sulfur levels comparable to that of lignite. *Id.* at 38543 (tables 5-6). But all bituminous units have been complying with the 1.2 lb/TBtu limit, thanks to a range of sulfur-resistant sorbents and other controls designed for high-sulfur environments. *Id.* at 38546/2-47/1; *see id.* at 38541/3 (noting the development of these sorbents).

And though some lignite coal can have high mercury content, not all lignite coal does. For example, North Dakota lignite has lower and less variable mercury content than Pennsylvania bituminous coal. *Id.* at 38543 (tables 5-6). But again, all bituminous units have been complying with the stricter standard for years.

To be sure, lignite has a unique set of characteristics. But each kind of coal has its own unique set of characteristics that, for one reason or another, makes it hard to control mercury emissions. *Id.* at 38549/1. Given the availability of controls that other coal-fired units have successfully used to comply with the 1.2 lb/TBtu limit, EPA reasonably concluded that the standard is feasible for lignite units. *See* Rural Mot. 13-14 (ignoring EPA's analysis of available controls).

Lest there be any doubt about whether lignite units can achieve 1.2 lb/TBtu, *cf. id.*, the record shows that two such units at the Twin Oaks facility have already done so—even before that level became the standard. 89 Fed Reg. at 38540/1 (reporting emission levels of 0.63 to 1.1 lb/TBtu). And two lignite units at the Red Hills facility have come reasonably close. *See id.* (reporting emission levels of 1.73 to 1.75 lb/TBtu). Notably, Twin Oaks uses Texas lignite and Red Hills uses Mississippi lignite. *Id.* at 38539/3-40/1. And both Texas and Mississippi lignite have much higher mercury content than North Dakota lignite. *Id.* at 38543 (table 5). Yet Twin Oaks and Red Hills have managed to meet or come close to the new standard. In this way, EPA assessed feasibility by considering the toughest scenarios for controlling lignite's mercury emissions. *Contra* Rural Mot. 14-15.

Movants are wrong that Twin Oaks is an "outlier" that uses controls not "technically feasible" at other units. *Id.* at 14. For a start, Movants mix up different power plants with "Oak" in their names: They cite a comment contending that selective catalytic reduction, used by Oak Grove's lignite plant, would not work at facilities burning North Dakota lignite. *Id.* (citing Lignite Council Comment 8). Oak Grove, however, is not Twin Oaks. And Twin Oaks, which meets the stricter standard, does not use selective catalytic reduction. *See* 89 Fed. Reg. at 38540/1 (noting that Twin Oaks uses selective *non*-catalytic reduction).

What Twin Oaks does use are sulfur controls and brominated sorbents—the most effective sorbents. *Id.* That sets it apart from many lignite units that are not using brominated or sulfur-resistant sorbents to control mercury, a fact that Movants disregard. *Id.* at 38540/2; Rural Mot. 14-15. Indeed, some lignite units could at times meet the 4.0 lb/TBtu standard without injecting any sorbents. 89 Fed. Reg. at 38540/2.[8] That further shows it is feasible for lignite units to meet the stricter standard: They need not install new controls; they simply need to use effective sorbents in the controls they already have. *See id.* at 38540/2. Doing so would also allow lignite units to inject sorbents at lower rates, something else that Movants disregard. Rural Mot. 15.[9]

This modest demand on lignite units is reflected in the cost estimate. Control costs are expected to be a "small fraction" of their revenue. 89 Fed. Reg. at 38549/1. And the standard's cost-effectiveness is $10,895 to $28,176 per

---

[8] These units could be burning lignite coal with low mercury levels or spraying oxidizing chemicals onto lignite before burning it.

[9] Even though Section 7412(d)(6) does not require EPA to identify more than one control technology, the agency did so, considering controls like brominated sorbents and chemicals designed for high-sulfur environments. *See* 89 Fed. Reg. at 38546/2-47/1; Resp. to Comments 84; *contra* Rural Mot. 13-14.

additional pound of mercury removed. *Id.* at 38548/2-3. That is comparable to and, if anything, less than the 2012 standard's cost (about $27,000 per pound). *Id.* at 38549/1 n.82.[10] At the same time, a disproportionate share of coal-fired units' mercury emissions comes from lignite units. *Id.* at 38549/1. Given all these factors, EPA properly concluded that costs are reasonable and the standard is achievable. *Id.* at 38547/2-49/2.

* * *

Movants' remaining contention is remarkable only for its brevity. Though Movants say that EPA failed to give a "reasoned explanation" of its feasibility conclusion and was put "on notice" that it is "flawed," they do not elaborate on what the supposed flaw was, proffering only a string cite of comments. States Mot. 11 & n.4. Such "obscure" briefing—"merely stating [an argument], in conclusory fashion and without visible support"—forfeited the argument. *Bd. of Regents of Univ. of Wash. v. EPA*, 86 F.3d 1214, 1221 (D.C. Cir. 1996); *see Davis v. Pension Benefit Guar. Corp.*, 734 F.3d 1161, 1166-67 (D.C. Cir. 2013) (disregarding argument made by incorporation, which skirts limits on brief length).

---

[10] Even if lignite units need to install new equipment, EPA estimated that costs would be relatively low. *See* 89 Fed. Reg. at 38549/1.

In the end, actual performance by regulated entities shows that the standards are feasible and will incur reasonable costs. Movants' contrary arguments, which ignore EPA's extensive analyses, are unlikely to succeed.

2. EPA properly did not rely on an analysis of benefits and costs, but reasonably considered them anyway.

Movants latch onto an analysis of monetized benefits and costs that EPA conducted to comply with Executive Order 12866. 89 Fed. Reg. at 38553/2. But in choosing the standards' stringency, EPA did not (and did not have to) use the monetized analysis done under the executive order. It relied instead on statutory factors. *Id.*; *see supra* Argument § I.A-B.1. Neither Section 7412(d)(6) nor legal precedent requires EPA to compare monetized benefits and costs in a technology review. *Cf. Michigan*, 576 U.S. at 759.

Meanwhile, in the analysis required by the executive order, EPA considered "all the costs and benefits" and concluded that the rule is a "worthwhile" exercise of its Section 7412(d)(6) authority.[11] 89 Fed. Reg. at 38553/3; *cf. Michigan*, 576 U.S. at 753 ("reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions" (emphasis omitted)).

[11] To be clear, the relevant costs and benefits come from the delta between the 2012 rule and the 2024 rule. 89 Fed. Reg. at 38553/2-3. Their scope is thus narrower than what EPA considered in finding that it is appropriate and necessary to regulate coal- and oil-fired power plants, a finding that no one challenged and is not at issue here. 42 U.S.C. § 7412(n)(1)(A); 88 Fed Reg. at 13956/1.

Movants focus on the monetized part of this analysis as evidence of arbitrary conduct. *E.g.*, States Mot. 6, 8-10; Westmoreland Mot. 14; Talen 28(j) Letter 2. The complete analysis, however, shows that EPA acted reasonably.

In benefit-cost analyses, it is easy to see a proposed action's net benefits (or net costs) when everything can be monetized. But when many things cannot, the agency's task becomes much harder. Here, EPA could not monetize the rule's chief benefit—reduced emissions of air toxics. 89 Fed. Reg. at 38553/2, 38515/3-16/2. Good epidemiological data on air toxics often does not exist: Exposure to these pollutants is often highly concentrated, but in smaller populations than those exposed to non-hazardous air pollutants. The small population size means that studies lack enough statistical power to detect effects of exposure. *Id.* at 38511/2, 38515/3-16/2; *FCC v. Prometheus Radio Project*, 592 U.S. 414, 427 (2021) (noting that it is not unusual for agencies to "not have perfect empirical or statistical data"). Without good data, economists cannot monetize harms from exposure or benefits from avoiding those harms. By contrast, the rule's costs *were* monetized, along with some ancillary benefits like reduced emissions of non-hazardous air pollutants. *See* 89 Fed. Reg. at 38515/3-16/1, 38558 (table 10).

Movants emphasize that costs exceed *monetized* benefits, resulting in high "'negative net monetized benefit.'" States Mot. 8 (quoting 89 Fed. Reg. at 38511/1); *see* Rural Mot. 19; Westmoreland Mot. 7, 14; Talen 28(j) Letter 2; *cf.*

Talen Mot. 23; Midwest Ozone Mot. 9-11. Yet as this Court warned in another Clean Air Act context, "simply weighing the monetizable costs against the monetizable benefits—and thereby excluding the primary benefits for which Congress created the [p]rogram—will yield a misleading result." *Sinclair Wyo. Refin. Co. v. EPA*, 101 F.4th 871, 889 (D.C. Cir. 2024). EPA, for its part, cautioned that the monetized analysis is "ill-suited" to air-toxics regulation because key benefits cannot be monetized. 89 Fed. Reg. at 38511/1, 38553/2.

EPA did, however, consider *all* costs and benefits, including unmonetized ones. *Id.* at 38553/1-59/1.[12] "That those benefits are not easily monetizable does not mean they are less valuable." *Sinclair*, 101 F.4th at 889. But without context, simply comparing costs with unmonetized benefits was meaningless. So EPA did what most of us do when deciding whether it is worthwhile to buy something without monetizing its benefits, be it shopping for groceries, hiring a dogwalker, or planning a vacation: We look to indicia of reasonableness like market price, affordability, and the advantages of having the good or service.

Here, costs reflect the relevant market price. As EPA explained in its technology review, almost all regulated units already have paid for the necessary controls to meet the surrogate standard, and the mercury standard's cost is

[12] In its public-interest argument, one Movant notes in passing that EPA ignored certain upstream costs and benefits. Midwest Ozone Mot. 10. That argument is too obscure to be preserved. *See Univ. of Wash. v. EPA*, 86 F.3d at 1221.

comparable to that of the 2012 standard. *Supra* Argument § I.B.1. Those costs are also a small fraction of regulated entities' revenue. *Id.* Meanwhile, the new standards' chief benefit—less air-toxics emissions—is the point of Section 7412. Those standards, expected to cut mercury by 9,500 pounds and non-mercury metals by 49 tons, would reduce human exposure to toxic chemicals and thus risk. 89 Fed. Reg. at 38511 (table 1), 38556/3; *see* Reg. Impact Analysis at 4-5 (noting the "lack of quantifiable risks" from mercury emissions, but that reductions are expected to affect overall mercury levels in fish (and thus the people who eat them)); 89 Fed. Reg. at 38515/2 (noting mercury's neurotoxic effects on children). The standards can also "enhance ecosystem services and improve ecological outcomes." 89 Fed. Reg. at 38556/3.

Considering all the benefits and costs, EPA noted that the final rule is worthwhile, though the choice of standards was based on statutory factors, not the benefit-cost analysis. *Id.* at 38553/3. Even if the rule had to be based on such an analysis, this is the sort of policy judgment that Congress instructed courts to leave to agencies. *See Ctr. for Auto Safety v. Peck*, 751 F.2d 1336, 1342 (D.C. Cir. 1985). Movants, having overlooked the complete benefit-cost analysis, are unlikely to succeed here.

3. EPA reasonably concluded that the rule would not imperil grid reliability.

EPA looked to statutory factors to choose the standards' stringency. It then modeled the rule's potential effect on the power sector. Reg. Impact Analysis 3-1 to 3-28. Based on that modeling, EPA concluded that the rule is not expected to impair reliability of the nation's electricity grid. 89 Fed. Reg. at 38526/1-2. Fixating on the conclusion rather than the analysis, Movants miss the point.

To begin, EPA has expertise to assess the impacts of its regulations on grid reliability. *Contra* States Mot. 11-12 (citing *Texas v. EPA*, 829 F.3d 405, 432 (5th Cir. 2016)). After all, Congress entrusted EPA to set standards for sources like power plants. 42 U.S.C. § 7412(d)(2), (n)(1). And EPA has been successfully regulating the power sector for years without causing blackouts or soaring electricity prices. *See* 89 Fed. Reg. at 38519/3, 38526/2-3 (giving examples of past rules). Movants' contrary take would bar EPA from tightening standards for power plants unless it consults certain energy-regulatory authorities—a condition found nowhere in Section 7412. Anyway, EPA did consult "other Federal agencies, reliability experts, and grid operators" here. Resp. to Comments 156 (also noting ongoing consultation with the Department of Energy, under a joint memorandum of understanding, on grid-reliability issues); *contra* States Mot. 12.

To assess the rule's potential energy impact, EPA used a state-of-the-art, peer-reviewed model. *See* Reg. Impact Analysis 3-1 to 3-4 (noting that industry also uses the model, which reflects information about the electricity market from utilities, industry experts, gas- and coal-market experts, financial institutions, and governments). The model projected that the rule would not lead any coal-fired capacity to retire. *Id.* at 3-18. On that basis, EPA concluded that the rule is not expected to affect grid reliability. 89 Fed. Reg. at 38526/1-2.[13]

This analysis discredits the bulk of Movants' grid arguments, which target EPA's conclusion about grid reliability. States Mot. 11-14. But Movants say little about the zero-retirement projection that undergirds that conclusion. Their only critique of the projection is that EPA allegedly underestimated retirements in the *2012* rule. *Id.* at 12-13; *cf.* Rural Mot. 25.

That critique is both irrelevant and wrong. It is irrelevant because an agency's failure to accurately predict the future does not make the underlying action—let alone a later action like the 2024 rule—unreasonable. *See Pub. Utils. Comm'n of State of Cal. v. FERC*, 24 F.3d 275, 281 (D.C. Cir. 1994) ("Predictions regarding the actions of regulated entities are precisely the type of policy judgments that courts routinely and quite correctly leave to administrative agencies."). And Movants' critique is wrong because although more coal-fired units retired than EPA had predicted in 2012, studies show that those retirements

[13] EPA also analyzed cumulative impacts of its recent power-plant rules, including this one, and concluded that they are unlikely to impair the power sector's ability to meet demand. *See* Resource Adequacy Memo; *contra* States Mot. 13-14.

were largely due to reduced demand for coal-fired electricity, driven by lower electricity demand and cheaper natural gas—coal's direct competitor. *See* 89 Fed. Reg. at 38526/1-27/1; 87 Fed. Reg. 7624, 7653/1-3 (Feb. 9, 2022). Of course, substituting natural gas for coal does not affect grid reliability.

And even though EPA projected that the rule would not cause retirements, it took commenters' grid concerns seriously. It explained that the kind of blackouts feared by commenters are unlikely to happen because power plants cannot unilaterally retire. Before they can shut down, power plants generally must undergo extensive processes imposed by state regulators and regional transmission organizations. 89 Fed. Reg. at 38526/2. These processes typically require analyses of the proposed retirement's impacts and identification of mitigation options. *Id.*; *see* Resp. to Comments 52-53 (noting that one of Colstrip's owners is in a regional program that addresses reliability planning). Sometimes, regulators offer temporary funding to keep the power plant open until longer-term measures are in place. 89 Fed. Reg. at 38526/2. And the Department of Energy, when facing an emergency electricity shortage, can issue orders allowing power plants to temporarily operate above their emission standards. *See id.* (citing 16 U.S.C. § 824a(c)).

Though Movants dismiss these failsafes as "unworkable," they do not explain why, either for Colstrip or more generally. Talen Mot. 13, 16-17; States

Mot. 20. An argument so skeletal is forfeited. *See Univ. of Wash.*, 86 F.3d at 1221; *Davis*, 734 F.3d at 1166-67. Besides, EPA did not rely on emergency resources in the rulemaking. It projected that the rule would not impair the grid. And it cited these resources in response to comments. 89 Fed. Reg. at 38526/1-2. Giving accurate responses is not arbitrary or capricious. *Contra* States Mot. 20.

C. The 2024 rule is not a pretext for regulating greenhouse gases.

EPA tightened the mercury standard and surrogate standard (for non-mercury metals) to reduce power plants' air-toxics emissions. The standards are not, as Movants imagine, a pretext for EPA to cut emissions of another pollutant—greenhouse gases—by "forc[ing] a nationwide transition away from coal." States Mot. 14.

Courts presume that, absent clear contrary evidence, agencies properly discharged their duties. *See United States v. Chem. Found.*, 272 U.S. 1, 14-15 (1926); *USPS v. Gregory*, 534 U.S. 1, 10 (2001). Movants offer no contrary evidence. Though they spin an elaborate tale of EPA's scheming, the record shows that it is nonsense. States Mot. at 14-16. EPA considered—and rejected—calls for even tougher standards. 89 Fed. Reg. at 38532 (table 4), 38538/1-2. It instead chose standards that are expected to result in zero coal-fired retirements. Reg. Impact Analysis 3-18. EPA cannot possibly be trying to shut down coal-fired units by not shutting them down at all.

Nor was the 2024 rule spurred by an "Executive Order *on climate change*." States Mot. 14; *see id.* at 3-4. That executive order, issued by President Biden in early 2021, broadly states his Administration's policy goals for protecting public health and the environment. 86 Fed. Reg. 7037, 7037 (Jan. 25, 2021). The goals cover more than just climate change and include "ensur[ing] access to clean air" and "limit[ing] exposure to dangerous chemicals." *Id.*

As for various statements by the White House and the Administrator that Movants assembled in service of their tale, States Mot. at 14-16, the Court cannot consider such extra-record material. *See* 42 U.S.C. § 7607(d)(7)(A) (defining scope of the record for judicial review); *CTS Corp. v. EPA*, 759 F.3d 52, 64 (D.C. Cir. 2014). Anyhow, nothing in those statements alters the conclusion that EPA's technology review complies with Section 7412.[14] *Cf. Dep't of Com. v. New York*,

[14] Movants also misread the extra-record material. Take the PowerPoint they cite as evidence of EPA's supposed intent to use different statutory authorities to "implement the Administration's climate agenda." States Mot. 15. In reality, the PowerPoint addresses all kinds of environmental problems created by power plants, and the statutes (like the Clean Air Act) that direct EPA to tackle them. *See* Chang Decl. Att. Likewise, the Administrator's PBS interview discussed power-plant regulations addressing not just climate concerns but also "waste and discharges in water" and "health-based pollution." Transcript, PBS interview with Michael S. Regan (June 30, 2022), *available at* https://www.pbs.org/newshour/show/epa-administrator-michael-regan-discusses-supreme-court-ruling-on-climate-change (last visited on July 20, 2024); States Mot. 15-16 & n.9.

588 U.S. 752, 781 (2019) ("a court may not reject an agency's stated reasons for acting simply because the agency might also have had other unstated reasons.").

D. Section 7412 directs EPA to regulate, not exempt, sources with obsolete controls that "could" retire.

Section 7412 aims to reduce air-toxics emissions through better technology. Yet Movants urge that the surrogate standard should not apply to Colstrip because it has obsolete controls and might retire at some point. *See, e.g.*, Talen Mot. 8, 10, 13-14; Westmoreland Mot. 12-15. That perverse view, if adopted, would upend the statutory scheme.

Technology reviews play a key role in Section 7412's technology-based regime. They allow EPA to tighten standards to keep up with technological advances. *See LEAN*, 955 F.3d at 1093. Deciding whether to tighten standards often means looking at what the best-performing sources are doing. Stricter standards, in turn, mean bringing stragglers in line with their peers. So of course technology reviews can impose costs on just a subset of regulated sources—but only because everyone else already paid those costs in the usual course of business. *See* Resp. to Comments 41; *e.g.*, Talen Mot. 10.

That was so here. Colstrip is the only U.S. coal-fired power plant without fabric filters or electrostatic precipitators, leaving it the highest emitter. Resp. to Comments 41. Indeed, Colstrip "struggled to meet the original 0.030 lb/MMBtu" standard and, in 2018, violated its permit by exceeding that level. 89 Fed. Reg. at

38531/2. Even so, Colstrip continues to use scrubbers that cannot reduce emissions to meet the 0.010 lb/MMBtu surrogate standard. Resp. to Comments 41, 52. In adopting a standard that almost all coal-fired units could already meet, EPA, in line with Section 7412, simply sought to bring Colstrip (and a small group of other laggards) to where the industry is as a whole. *Id.*

Movants think that Colstrip's choice—against industry trends—to use inferior controls ought to exempt it from the stricter standard. Because Colstrip would incur disproportionate costs to meet that standard, they say, it deserves a break. Talen Mot. 8, 10, 15-16; Westmoreland Mot. 7, 10, 14-15. Or, simply put, Movants want to reward those who hang on to outdated controls. The Court should reject their attempt to subvert Section 7412.

Similarly, EPA reasonably declined to exempt Colstrip on account of possible retirement.[15] The agency examined the potential interaction between the surrogate standard and the greenhouse-gas rule. *Contra* Talen Mot. 11-12. In that context, it considered whether to create a subcategory for units facing near-term retirements. Resp. to Comments 38; 89 Fed. Reg. at 38527/1-3. EPA reasonably declined because "only a few facilities" would be eligible for a near-term

[15] Though Movants blame EPA for "compelling" Colstrip to retire by 2031, the specter of retirement has long haunted that facility. Talen Mot. 11. Disagreement among Colstrip's owners about how and when to retire has led to years of litigation and even involvement by the Montana state legislature. Lebsack Decl. ¶¶ 25- 26.

retirement subcategory: Less than a quarter of coal-fired units had preexisting plans to retire between 2029 and 2032; only three could not comply with the stricter standard. 89 Fed. Reg. at 38527/3. Colstrip did not figure in this tally, having never said that it would retire. Lebsack Decl. ¶¶ 25-31; *see* Talen Mot. 13-14 (conflating Colstrip with units that announced retirement); Westmoreland Mot. 15 (faulting EPA for ignoring impact from hypothetical retirement). So a retirement subcategory would not have materially reduced overall compliance costs and would have had "little utility." 89 Fed. Reg. at 38527/3.

Nor was it a viable alternative to exempt units that, like Colstrip's, "could decide to retire" but have no publicly stated plans to do so. Talen Mot. 14 (emphasis omitted); *see id.* at 13. If EPA had done that, then every coal-fired unit would be exempted, for they will all retire at some point. *Cf.* Resp. to Comments 38 ("The Agency has not previously subcategorized based on retirements under [Section 7412], and do[es] not find it appropriate to do so at this time."). EPA reasonably declined to exempt potentially retiring units from its standards.

Ultimately, Section 7412 aims to continue to reduce air-toxics emissions through better technology. EPA tightened the surrogate standard to bring a few units up to par with the rest of the industry. It would defeat Section 7412's text and design to allow those units to keep using obsolete controls until whenever they decide to retire. Movants' contrary argument is unlikely to succeed.

II. Movants show no irreparable harm.

The only kind of injury that justifies the extraordinary remedy of a stay is an irreparable one. *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985) (per curiam). An irreparable injury "must be both certain and great." *Id.* It must have such "*imminence*" that there is a "clear and present need for equitable relief…." *Id*. (internal quotation marks omitted). Movants fall short of that high bar: They speculate about possible grid problems, and they offer no evidence of great, imminent harm.

A. Movants speculate about threats to the grid.

Rehashing their merits arguments, Movants say that the 2024 rule threatens grid reliability. *E.g.*, Rural Mot. 23-24; States Mot. 18-21; Talen Mot. 21-22; Midwest Ozone Group Mot. 7-8. EPA showed that the rule is not expected to cause any retirements. Reg. Impact Analysis 3-18. When Movants' claims of harm conflict with the record, the Court should focus on the record and consider the applicable arbitrary-and-capricious standard. 42 U.S.C. § 7607(d)(7)(A), (9). The Court is not well-positioned, especially at the stay stage, to weigh the credibility of Movants' extra-record declarations against EPA's record findings.

Nor do the declarations pass muster under *Wisconsin Gas*. They are long on possibilities but short on certainty, dwelling on the parade of horribles that could ensue if—*if*—coal-fired units were to retire. *E.g.*, Barkey Decl. ¶ 5; Cottrell Decl.

¶¶ 23-24; Friez Decl. ¶¶ 5, 7; Hines Decl. ¶ 23; Lane Decl. ¶¶ 11, 21, 23, 26; Lebsack Decl. ¶ 11.e-f; Nowakowski Decl. ¶ 7; Tschider Decl. ¶ 23. But the declarants do not specify whether and when that contingency would ever occur. So, as these examples show (with emphases added), they hedge:

- "*If* the Final Rule forces even more coal generation sources to shut down, …it will significantly impact grid reliability…." Vigesaa Decl. ¶ 20.
- "[Lignite Energy Council]'s members are actively trying to determine *if* they will be able to comply…and still remain commercially viable." Bohrer Decl. ¶ 18.
- "I am concerned that the reduced level of allowable fPM *could* lead coal-unit owners…to retire those units…." Rickerson Decl. ¶ 12.
- "The Final Rule *may* cause coal plants in the MISO and PJM grids to close." Huston Decl. ¶ 14.
- "The level of annualized costs to comply with the MATS Final Rule *may* be cost prohibitive and lead to a premature retirement of Colstrip." Lebsack Decl. ¶ 46.

Movants' briefing likewise resorts to *if*s, *could*s, and *may*s to argue harm. *E.g.*, States Mot. 1, 20; Talen Mot. 21. But as EPA explained, regulators have extensive processes and backstops and other measures to protect grid reliability. 89 Fed. Reg. at 38526/2. So there is no credible evidence that the rule will cause power plants to abruptly shut down and imperil the grid. Movants thus flunk *Wisconsin Gas*'s certainty requirement. And the Fifth Circuit's analysis of different declarations in a different case cannot alter the conclusion that follows from *Wisconsin Gas*'s binding precedent. States Mot. 21-22 (citing *Texas*, 829 F.3d at 416, 434).

B. Movants offer no evidence that they will incur great costs imminently.

Despite their voluminous submissions, Movants fail to show that they will incur hefty costs during the judicial-review period. No one here disputes that some coal-fired units will have to spend money to comply with the standards, or that in some cases those costs may pass on to ratepayers in the form of higher electricity bills. The question on a stay motion is whether Movants have shown that their harm is so "great" and "imminen[t]" that the Court should suspend a duly promulgated regulation before full merits briefing. *Wis. Gas*, 758 F.2d at 674 (emphasis omitted); *cf. Ohio*, 144 S. Ct. at 2053 (recognizing that stay applicants would incur hundreds of millions of dollars in compliance costs "during the pendency of this litigation"). No such harm exists for either regulated Movants who own or operate coal-fired units, or non-regulated Movants like states and mining companies.

1. Regulated Movants.

Though the power companies declare that they must start compliance work right now, they offer neither evidence nor reason for the rush. Their threadbare, conclusory assertions are not "proof indicating that the harm is certain to occur in the near future." *Wis. Gas*, 758 F.2d at 674.

For one thing, the rule's compliance deadline is three years away. 89 Fed. Reg. at 38519/3. On top of that, power plants can apply—to their permitting authorities, many of whom are represented by Movants—for a one-year extension (until July 2028). *Id.* The record also shows that compliance work to meet the surrogate standard typically takes two years or less, and the mercury standard, under a year. *See* Sargent & Lundy Report 7; 2023 Andover Report 48-49. Yet Movants offer no evidence of why power plants need to work on compliance right away, or why the one-year extension is unavailable to them. *See, e.g.*, Bohrer Decl. ¶¶ 18, 22-23; Bridgeford Decl. ¶ 8; Courter Decl. ¶ 12; Lebsack Decl. ¶¶ 35-37; McCollam Decl. ¶¶ 34, 37; McLennan Decl. ¶¶ 37-38, 45, 52; Purvis Decl. ¶¶ 19, 22-23; Rural Mot. 20, 22, 24-25; States Mot. 18; Talen Mot. 20-21; *see also* Order, *Denka Performance Elastomer LLC v. EPA*, Case No. 24-1135 (D.C. Cir. July 17, 2024) (denying petition for reconsideration of order denying stay motion, because movant failed to show irreparable harm "given that it could but has not requested from respondents an extension of the deadline to comply with the rule under review").[16]

The purported rush is all the more baffling when many power plants can show compliance using emissions averaging. That is, a qualifying facility can average emissions from its regulated units. *See* 40 C.F.R. § 63.10009; 89 Fed Reg. at 38521/3. So long as those units' average emission rate meets the standard, the entire facility is in compliance. Averaging, in short, allows some units to emit above the standard.[17]

Take the Spurlock facility, owned by Movant East Kentucky Power Cooperative. Though Mr. Purvis's declaration (at ¶¶ 13-15, 21-26, 33-34, 36) focuses on Spurlock Unit 3's high emissions, Spurlock's other units seem to emit at rates well below the surrogate standard. *See* 2024 Technical Memo Att. 2 at 71-79.[18] Yet Mr. Purvis never explains why Spurlock chooses not to average its units'

---

[16] Some Movants cite the rule's monitoring requirements as a cause of their alleged harm. *See* Tschider Decl. ¶ 20; Midwest Ozone Mot. 6-7 (mentioning costs of Continuous Emissions Monitoring Systems); Rural Mot. 20 (referring to "PM CEMS"). But Movants never attack the monitoring requirement on the merits, thus giving this Court no reason to stay it. So any harm from that requirement cannot factor in the stay analysis.

[17] The technology review did not account for emissions averaging as a compliance strategy. In this way, EPA overestimated compliance costs to the benefit of regulated entities.

[18] *See also* https://cfpub.epa.gov/webfire/reports/esearch.cfm (last visited July 22, 2024) (under Air Emission Reports, search facility under "Submitting Organization and/or Facility Name").

emissions. Publicly available data suggests that other Movants' facilities may also be eligible for emissions averaging. *See* n.18; Collam Decl. (Basin Electric); McLennan Decl. (Minnkota); Tschider Decl. (Rainbow).

Together, the three-year deadline, the one-year extension, and the availability of emissions averaging vitiate Movants' imminence claims.

2. Non-regulated Movants.

Though they submit declarations from power companies, Movants like states and mining companies are not regulated by the rule. So they cannot count any harm to the power companies as their own. *See Nken*, 556 U.S. at 426 (asking "whether *the applicant* will be irreparably injured" (emphasis added)). Instead, these Movants must prove their own great, imminent harm. They fail to do so.

First, Movants offer no evidence that pass-through compliance costs would result in any great electricity-rate increase to them. *See* States Mot. 17. EPA projected that rate increases would be minimal, between 0.1 to 0.5 percent—and in line with one declarant's estimate. Reg. Impact Analysis 3-25 to 27; *see* Fedorchak Decl. ¶ 26 (predicting "at least a 0.5 percent increase"); *contra* States Mot. 17. Other declarants admit that some ratepayers can switch providers to avoid higher rates. Tschider Decl. ¶ 29; Lebsack Decl. ¶¶ 14-15. And though Movants try to inflate the bill by counting what non-Movant ratepayers would have to pay, only harm to the stay applicant counts. States Mot. 17; *see, e.g.*, Lane Decl.

¶ 23 (stating that compliance "will cost West Virginia customers nearly $40 million in added rates"); Vigesaa Decl. ¶ 24 (counting all ratepayers across multiple states); *Nken*, 556 U.S. at 426; *cf. Alfred L. Snapp & Son, Inc. v. Puerto Rico ex rel. Barez*, 458 U.S. 592, 610 n.16 (1982) ("A State does not have standing as *parens patriae* to bring an action against the Federal Government.").

Second, though state-regulator declarants vaguely object to devoting resources to understand, implement, and mitigate the rule, those exertions do not count because they are based on speculation that the rule would imperil the grid. *See* Fedorchak Decl. ¶ 7; Lane Decl. ¶¶ 18, 30; States Mot. 17-18. Nor do the declarants explain why those tasks must happen now (or prove any costs). This silence is especially odd when many state regulators have a say in compliance timing because they can grant one-year extensions. Suffice to say, then, that their conclusory statements are not proof of irreparable harm.[19] *See Wis. Gas*, 758 F.2d at 674. That is also true of conclusory assertions of harm by Movant Midwest Ozone Group (at 5-7), which has neither identified its members nor explained how it has standing to seek a stay.

Finally and most fundamentally, non-regulated Movants tie various alleged harms to how power companies would respond to the standards. *E.g.*, Cottrell

---

[19] State Movants do not allege harm to their sovereign interests, let alone that those interests are "expressly recognize[d]" by the Clean Air Act. *Ohio*, 144 S. Ct. at 2053; States Mot. 17-22.

Decl. ¶ 23; Fedorchak Decl. ¶ 26; Friez Decl. ¶¶ 11-17; Raad Decl. ¶ 9; States Mot. 17; Westmoreland Mot. 19-20. But their piggybacking attempts fail because the power companies cannot show imminence. *See supra* Argument § II.B.1. So non-regulated Movants cannot either.

III. A stay would harm the public interest.

In Section 7412, Congress decided that less toxic air pollution is better, and that it is worthwhile to keep reducing pollution through improved technology—even when existing standards offer an ample margin of safety. To Congress, technological progress, not just our ability to assess risk, drives the regulation of air toxics. The 2024 rule delivers those benefits. Staying the rule would deny the public the benefits that Congress sought to confer. *See United States v. Oakland Cannabis Buyers' Co-op.*, 532 U.S. 483, 497 (2001) ("a court sitting in equity cannot ignore the judgment of Congress, deliberately expressed in legislation." (internal quotation marks omitted)).

Movants' refrain that earlier standards are safe enough ignores statutory design and congressional intent. Midwest Ozone Mot. 8-10; Rural Mot. 26; States Mot. 22-23. Their other arguments recycle debunked merits and harm arguments. Midwest Ozone Mot. 9-10; Rural Mot. 26; States Mot. 22; Talen Mot. 22-23; Westmoreland Mot. 21-22. Movants, in short, cannot show that a stay would serve public interest.

IV. Any stay should be narrowly tailored.

Movants are not entitled to a stay. But if the Court were to disagree, relief must be narrowly tailored. *See Gill v. Whitford*, 585 U.S. 48, 68 (2018). Movants' merits arguments target only the rule's surrogate standard for non-mercury metals and mercury standard for lignite units. They do not address the rule's other provisions, such as revisions to monitoring requirements. *See* 89 Fed. Reg. at 38509/3 (summarizing the rule's key provisions). Any stay thus should be limited to the two severable standards. *See id.* at 38518/3.

Likewise, were the Court to conclude that only some Movants meet their burden under *Nken*, a stay should pause the rule's application only as to the successful parties. For example, Talen's and Westmoreland's motions address only Colstrip, which burns subbituminous coal. Lebsack Decl. ¶ 8. Any stay based on their motions should apply only to Colstrip and certainly should not touch the mercury standard for lignite units. Similarly, any stay based on arguments about the mercury standard should not touch the surrogate standard.

CONCLUSION

For all their objections, Movants are out of step with the power-plant industry. The vast majority of coal-fired units can meet the standards. Only a small group needs to up its game by using better controls. And that—using better technology to reduce toxic air pollution—is what Congress amended Section 7412 to do. There is no error or emergency to justify the extraordinary relief Movants seek. The Court should deny the stay motions.

Submitted on July 22, 2024.

Todd Kim
Assistant Attorney General

/s/ Sue Chen
Sue Chen
Redding Cofer Cates
U.S. Department of Justice
Environment & Natural Resources Div.
Environmental Defense Section
P.O. Box 7611
Washington, D.C. 20044
202.305.0283
sue.chen@usdoj.gov

Of counsel
Matthew McNerney
U.S. Environmental Protection Agency
Office of General Counsel
Washington, D.C.

CERTIFICATES OF COMPLIANCE AND SERVICE

I certify that this document complies with Fed. R. App. P. 32(a)(5) and (6) because it uses 14-point Times New Roman, a proportionally spaced font.

I also certify that this document complies with the Court's July 1, 2024, Order because by Microsoft Word's count, it has 11,909 words, excluding the parts exempted under Fed. R. App. P. 32(f).

Finally, I certify that on July 22, 2024, I electronically filed this document with the Court's CM/ECF system, which will serve each party.

/s/ Sue Chen

ORAL ARGUMENT NOT YET SCHEDULED

Nos. 24-1190 and 24-1217 (consolidated with No. 24-1119)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

TALEN MONTANA, LLC,
Petitioner,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY and
MICHAEL S. REGAN, Administrator, U.S. Environmental Protection Agency,
Respondents.

NORTHWESTERN CORPORATION,
Petitioner,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY and MICHAEL S.
REGAN, Administrator, U.S. Environmental Protection Agency,
Respondents.

On Petitions for Review of a Final Action of the
U.S. Environmental Protection Agency

PETITIONER TALEN MONTANA, LLC AND
PETITIONER NORTHWESTERN CORPORATION'S
JOINT REPLY IN SUPPORT OF MOTION FOR STAY

(*Counsel listed on inside cover*)

Joshua B. Frank
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street N.W.
Washington, D.C. 20001
Tel.: (202) 639-7748
(202) 639-1130
joshua.frank@bakerbotts.com
joshua.lee@bakerbotts.com

Counsel for Petitioner
Talen Montana, LLC

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue N.W.,
Suite 900
Washington, D.C. 20005
Tel.: (202) 442-3555
magid.chip@dorsey.com

Michael Drysdale (*Of Counsel*)
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402
Tel.: (612) 340-5652
drysdale.michael@dorsey.com

Counsel for Petitioner
NorthWestern Corporation
d/b/a NorthWestern Energy

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

CASES

FEDERAL REGISTER

GLOSSARY

Colstrip	Colstrip Power Plant
EPA or Agency	U.S. Environmental Protection Agency
Final Rule	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review: Final Rule, 89 Fed. Reg. 38508 (May 7, 2024)
GHG Rule	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: Final Rule, 89 Fed. Reg. 39798 (May 9, 2024)
fPM	Filterable particulate matter
GHG	Greenhouse gas
MATS or MATS Rule	National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Final Rule, 77 Fed. Reg. 9304 (Feb. 16, 2012) (commonly referred to as "Mercury and Air Toxics Standards")
WRAP	Western Regional Adequacy Program

INTRODUCTION

The Colstrip Power Plant ("Colstrip") is critical to Montana and beyond. It delivers necessary power to meet growing regional demand, supports grid reliability, provides jobs, and drives the Montana economy. Even opponents' declarants do not want Colstrip to retire.[1]

Yet EPA's Final Rule—when combined with the GHG Rule—forces Colstrip's premature demise. Even if Colstrip decides to comply during the short window before the GHG Rule forces closure, the impacts on the owners and customers will be profound. With no stay, the Final Rule compels Colstrip's owners to make expedited business and regulatory decisions during this litigation that cannot be undone if the rule is ultimately overturned.

Among this lawsuit's stakeholders, Colstrip stands alone. Nearly half the rule's costs are imposed on Colstrip. No Opposition denies Colstrip is the Final Rule's primary and deliberate target. Yet Petitioners' arguments about the rule's legality ***as it concerns Colstrip*** are deflected or ignored. Instead, opponents deride Colstrip as a "laggard," raising an already-resolved 2018 compliance issue.

Colstrip is not a villain. Colstrip improved fPM controls in 2018 and has since been over-complying with the MATS standard by a significant margin. Colstrip emits fPM at a slightly higher rate than some others. But (1) Colstrip's fPM controls

[1] Wetherelt Decl. ¶¶ 4, 12, Env't Intervenors Opp'n Ex. 5.

already achieve 99.6% control, and (2) health risks from Colstrip's fPM emissions are an order of magnitude below levels EPA deems safe.

Colstrip, however, ***is*** the plant most burdened by the Final Rule. Additional emission controls would cost Colstrip $350M. It was thus incumbent on EPA to grapple with Colstrip-specific issues raised in comments. EPA failed to do so.

While other petitioners raise meritorious arguments that warrant staying the entire rule, Colstrip is sui generis.[2] EPA's arbitrary and capricious treatment of Colstrip-specific issues demands a stay.

ARGUMENT

I. Irreparable Injury

Opponents ignore that the purpose of a stay is to minimize the risk that parties must make irreversible and consequential decisions during litigation. Without a stay, Colstrip's "relative position[]" will be upset. *See Starbucks Corp. v. McKinney*, 144 S. Ct. 1570, 1576 (2024).

A. Opponents Ignore Colstrip's Immediate Harms.

Opponents generally aver that petitioners collectively have shown no immediate harm. They rely on the familiar trope that compliance is three years away. *E.g.*, EPA Opp'n 45. Yet they ignore Colstrip; with no stay, irreparable harms

[2] Even opponents recognize Colstrip's unique position, requesting that any stay for Colstrip not be extended to others. EPA Opp'n 50; Env't Intervenors Opp'n 13.

have arisen and will compound due to the rule's tight compliance timeframe and the extensive equipment installation required:

(1) "Talen Montana has ***already begun the process of expending funds*** to study the compliance options and timelines, and millions of dollars will be required to continue engineering and design efforts later this year." Also, "major construction activities begin[] by Spring of 2025." Lebsack Decl. ¶ 51, Mot. Ex. 1 (emphasis added).

(2) "[B]y the end of the first quarter of 2025, material purchasing will begin and multiple contract awards will ramp up commitments and spending rapidly on a $350 million project." *Id.* ¶ 36.

(3) The compliance costs are large enough to threaten NorthWestern's financial viability if rate recovery is not allowed,[3] and NorthWestern cannot know whether rate recovery will be allowed within the required compliance timelines. Hines Decl. ¶¶ 23–24, Mot. Ex. 2.

By extension, Environmental Intervenors ignore Colstrip's reality:

(1) New pollution control is required, not "possibly" needed. *Compare* Lebsack Decl. ¶ 33, *with* Staudt Decl. ¶ 6, Env't Intervenors Opp'n Ex. 1.

---

[3] Even if Environmental Intervenors are correct to consider costs "relative to" expenses and revenues, Opp'n 14, costs threatening the financial viability of a Petitioner meets that standard. Regardless, their take is unsupported. *See, e.g.*, *In re NTE Connecticut, LLC*, 26 F.4th 980, 990–91 (D.C. Cir. 2022) (irreparable injury of "future revenues" worth "millions").

(2) That project will take "three years minimum," not "around two years." *Compare* Lebsack Decl. ¶ 35 and Attachment A at 1-3 (Burns & McDonnell study briefed to Colstrip's leadership concluding "this project will take 36-42 months"), *with* Staudt Decl. ¶¶ 6, 43.

(3) Thus, "work must begin the summer of 2024 . . . with detailed engineering and design in the fall of 2024," not "no need . . . during the litigation period" or "until around late-2026." *Compare* Lebsack Decl. ¶ 35, *with* Staudt Decl. ¶¶ 12, 17–20.

(4) "[Colstrip] must permanently cease operation by the end of 2031" under the GHG Rule and thus the amortization period is at most "4.5 years," not "a typical 20-year" which hinges on the assumption that "Colstrip does not have an ***announced*** retirement date." *Compare* Lebsack Decl. ¶¶ 41–44, *with* Staudt Decl. ¶ 42 (emphasis added).

Additionally, the irreparable injury to Colstrip goes beyond immediate financial harms. The compliance timing requires Colstrip's owners to make highly consequential, irreversible business and regulatory decisions now. Lebsack Decl. ¶¶ 51–54. If this litigation is left to run its course, Colstrip will have committed to a path that cannot be undone; and if that path is compliance, Colstrip's complex and diverse ownership structure will consume further time and resources. *Id.* ¶¶ 26–31. Only a stay can prevent that.

B. Opponents Downplay Colstrip's Retirement Impacts.

Opponents project confidence that grid disruptions are unlikely because EPA projects no plant retirements from the Final Rule. *But see, e.g.*, Talen Mont. Cmts. 6–7, Mot. Ex. 6; NorthWestern Cmts. 20, Mot. Ex. 5. EPA cites a string of petitioners' declarations which, from its perspective, all "hedge" on retirement. Opp'n 43. Leaving aside that expecting companies to announce plant closures in litigation briefs soon after a regulation's issuance is unreasonable, Petitioners were unequivocal that the Final Rule's impact, when combined with the GHG Rule, "will" force Colstrip to retire, likely by 2027.[4] Lebsack Decl. ¶ 11.f and Attachment B at ¶ 33; *see also* Hines Decl. ¶ 9.a. Even where the precise consequences are less certain, opponents' fixation on "*if*s, *could*s, and *may*s," EPA Opp'n 32, misses the mark. Forcing an irreversible business/regulatory decision now puts Petitioners in a materially harmful position.[5]

Finally, opponents claim Petitioners cannot argue third-party harm. State Opp'n 8 (citing Mot. 21–22, discussing grid reliability and Montana's economy); *cf.* EPA Opp'n 47. To start, as the Montana Balancing Authority, NorthWestern is legally obliged to maintain grid reliability and deliver service at a reasonable cost.

[4] While EPA contends that Colstrip's "specter of retirement" is not new, Opp'n 40 n.15, the Final Rule—when combined with the GHG Rule—forces the issue.

[5] Petitioners address the Oppositions' grid reliability arguments *infra* pages 8–10.

The consumers' harm is NorthWestern's harm. At minimum, these harms address the public interest factor favoring a stay, *infra* Section III.

II. Merits

Opponents fail to seriously respond to Colstrip-specific arguments raised by Petitioners. This is unsurprising given EPA's failures in the record. Just recently the U.S. Supreme Court granted a stay because it was "likely" that EPA's regulation (1) was "not 'reasonably explained,'" (2) lacked "a satisfactory explanation," and (3) "ignored 'an important aspect of the problem' before it." *Ohio v. EPA*, 144 S. Ct. 2040, 2054 (2024). This Court should reach the same conclusion because EPA made the same errors here about Colstrip.[6]

Interaction with the GHG Rule. EPA makes two passing references that it considered the interaction between the GHG Rule and the Final Rule. Opp'n 35 n.13, 40. The first cites EPA's Resource Adequacy Memo, which rehashes generalized observations on reliability and how any retirement will be "orderly."[7] *But see* Mot. 13, 15–17 (explaining how EPA gave no specific consideration to Colstrip's unique conundrum despite Petitioners' extensive comments on the negative interactions of the two rules). Given the Final Rule's focus on Colstrip,

---

[6] Petitioners incorporate their Motion, their 28(j) Letter, and other petitioners' arguments to address whether EPA exceeded its authority.

[7] State Intervenors' reliance on EPA's Regulatory Impact Analysis, Opp'n 24, fares no better. EPA did not even cite this document for such basis.

EPA's failure to meaningfully consider Colstrip-specific impacts was arbitrary and capricious. The second reference cites EPA's responses concerning retirement subcategories, discussed below. *See also* Mot. 13–15.

Retirement subcategorization. EPA makes two points. First, EPA repeats an arbitrary assumption from the Final Rule—that subcategorization should be relevant only to facilities that have ***already announced*** retirement. *Compare* Opp'n 40–41 (discussing how "'only a few facilities' would be eligible," those that "had preexisting plans to retire"), *with* Mot. 13–14 (citing 89 Fed. Reg. 38508, 38527 (May 7, 2024)). Petitioners requested that EPA consider a subcategory because the Final Rule and GHG Rule collectively accelerate Colstrip's retirement. Petitioners requested a subcategory as an offramp, aligned with the GHG Rule, that would permit an orderly retirement with more time for replacement resources. *E.g.*, Talen Mont. Cmts. 21. EPA's failure to meaningfully consider this option on the record and limiting consideration to facilities that had announced retirement (as opposed to facilities that might choose to retire given the Final Rule) is arbitrary and capricious.

EPA's response that a retirement subcategory "would not have materially reduced overall compliance costs and would have had 'little utility,'" Opp'n 41 (quoting 89 Fed. Reg. at 38527), is nonsense. As discussed in Petitioners' Motion, if Colstrip opted into the requested subcategory, the rule's costs would be halved.[8]

Second, EPA tackles a strawman. *Id.* ("If EPA had done that, then every coal-fired unit would be exempted, for they will all retire at some point."). Petitioners asked for a date certain in their comments and sought coordination with the GHG Rule. *E.g.*, Talen Mont. Cmts. 21. Because Petitioners never sought an open-ended retirement date, EPA's reasoning is not only nonsensical and non-responsive—it is post hoc reasoning that should be rejected under *SEC v. Chenery Corp.*, 332 U.S. 194 (1947).

An agency must consider "significant and viable" and "obvious" alternatives. *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). Indeed, EPA took exactly the path Petitioners requested here in the GHG Rule. 89 Fed. Reg. 39798, 39841–42 (May 9, 2024) (subcategorizing based on retirement dates, wholly exempting units retiring before 2032, and not limiting eligible facilities to those that had already announced plans to retire).

Grid reliability. Opponents' generalized rejoinder on nationwide reliability ignores that there is no nationwide grid, but rather a patchwork of regional grids.

---

[8] Similarly, Environmental Intervenors' criticism of a "single-source subcategory," Opp'n 11, is misplaced. A retirement subcategorization would not be "single-source" because other units could opt into the subcategory through retirement. Mot. 14. But even if it were, such criticism begs the question of why that would be improper, when no one contests Colstrip is uniquely situated.

NorthWestern Cmts. 13. EPA thus fails to grapple with Colstrip- and Montana-specific concerns, which are at the heart of this Final Rule. It is EPA being "skeletal" when it accuses Petitioners of the same.[9] Opp'n 37. Petitioners cited to NorthWestern's substantial comments on Montana-specific reliability issues to show what EPA ignored. Petitioners then explained that EPA's rationale behind wishing away Montana's reliability concerns fails for at least two reasons. ***First,*** "limitations on" both power "supply and transmission" means that the Western Regional Adequacy Program ("WRAP") cannot ensure sufficient replacement power—at least not "under the regulation's timelines."[10] Mot. 16. This point was further elaborated in the "Immediate Irreparable Injury" section of the Motion, *id.* at 21–22, the supporting declarations, and NorthWestern's comments cited therein. ***Second,*** the Motion's footnote 7 pointed out that the Department of Energy authority relied upon by EPA is limited to national emergencies and unforeseen events, not a forced retirement due to regulatory obligations.

---

[9] Certainly no forfeiture. *Cf. Bd. of Regents of Univ. of Wash. v. EPA*, 86 F.3d 1214, 1221 (D.C. Cir. 1996) (one-footnote argument "without visible support"); *Davis v. Pension Benefit Guar. Corp.*, 734 F.3d 1161, 1166–67 (D.C. Cir. 2013) (appealing nine claims but arguing five).

[10] Environmental Intervenors also mimic EPA's response in the Final Rule by proclaiming NorthWestern's involvement in the WRAP alleviates reliability concerns. Goggin Decl. Attachment 2 at 10, Opp'n Ex. 6. NorthWestern, as the balancing authority, has stated that available measures are insufficient. Regardless, such declarations are legally irrelevant to merits issues; Petitioners' point is that EPA ignored NorthWestern's comments.

Environmental Intervenors attempt to address Colstrip-specific reliability concerns through a new declaration attacking the accuracy of the Hines Declaration, which principally restated NorthWestern's record comments and Montana's testimony. *See* Opp'n 19–20. Substantively, they focus on the wrong variable—peak demand in isolation—rather than the problem highlighted by NorthWestern: high demand coupled with poor conditions for generation from renewables. It is the latter scenario where Colstrip is vital. NorthWestern Cmts. 2–3, 10–12. They couple this with wishful thinking, assuming that imminently expiring capacity contracts can be readily extended.

More fundamentally, their (improper) attempt to backfill the record reinforces Petitioners' point that this is a serious issue that EPA should have more meaningfully considered given the substantial comments (500+ pages) NorthWestern put into the record on this point. EPA's failure to meaningfully assess NorthWestern's comments demonstrates arbitrary and capricious rulemaking.

Cost-effectiveness. Finally, cost-effectiveness has always been one of the main factors considered in technology review. Petitioners commented about the cost-(in)effectiveness of the rule as applied to Colstrip (i.e., on a dollars-per-ton removal basis). Specifically, Petitioners first commented that no vendor could guarantee fPM removal to the level at Colstrip assumed by EPA and its technical memorandum (the Sargent & Lundy Report), yielding much higher costs per ton of removal than EPA's estimates. *See* Talen Mont. Cmts. 14–16. The Final Rule and supporting regulatory documents were silent on this concern. With no record support, EPA now hypothesizes that Petitioners' comments are incorrect. *See* Opp'n 21–22.

Petitioners also commented that cost-effectiveness would skyrocket because EPA assumed costs would be spread over a long period, not accounting for the one-two punch of the GHG Rule (which forces retirement by 2032) and the Final Rule (which likely accelerates that date to 2027). The Final Rule failed to respond to Colstrip-specific comments on the risk of premature retirement from the GHG Rule and its impact on cost-effectiveness at Colstrip. EPA's attempts to backfill the record with arguments about "most coal-fired units," Opp'n 20, likewise fail to address Colstrip-specific retirement arguments.

III. Balance of Equities and Public Interest

No declarations by Environmental Intervenors nor EPA's contortions can overcome EPA's own risk assessment, which demonstrates that the status quo risk from Colstrip's emissions is infinitesimally small. EPA has concluded that Colstrip's cancer risk is 0.147-in-1M, almost seven times lower than the 1-in-1M risk that is considered scientifically insignificant. *See* Am.'s Power Mot. 5–9. Relatedly, Environmental Intervenors' general truisms that fPM exposure harms health ignores that EPA has already determined Colstrip's emissions are not likely to cause adverse health and environmental effects. *See, e.g.*, 89 Fed. Reg. at 38517.

Attempts to lower that risk even further cannot favor the public interest when such choice presents (1) inherent opportunity costs (i.e., resources that could be devoted elsewhere), and (2) actual costs (in Colstrip's case, Montana's economy, grid reliability, and electricity price increases for consumers).

Finally, EPA's demand to respect Congress's judgment, Opp'n 49, begs the question. EPA acted outside of that judgment: Clean Air Act Section 112(d)(6), and the Administrative Procedure Act's directive to not act arbitrary and capricious or otherwise not in accordance with law.

CONCLUSION

A stay should be granted to maintain the status quo and allow a thoughtful decision to be made on Colstrip's future with the benefit of a full understanding of the Final Rule's legal status.

DATED: July 29, 2024

Respectfully submitted,

<u>/s/ Joshua B. Frank</u>

Joshua B. Frank
C. Joshua Lee
BAKER BOTTS L.L.P.
700 K Street N.W.
Washington, D.C. 20001
Tel.: (202) 639-7748

<u>/s/ Michael Drysdale</u>

Creighton R. Magid
DORSEY & WHITNEY LLP
1401 New York Avenue N.W.,
Suite 900
Washington, D.C. 20005
Tel.: (202) 442-3555

(202) 639-1130
joshua.frank@bakerbotts.com
joshua.lee@bakerbotts.com

Counsel for Petitioner
Talen Montana, LLC

magid.chip@dorsey.com

Michael Drysdale (*Of Counsel*)
DORSEY & WHITNEY LLP
50 South Sixth Street, Suite 1500
Minneapolis, MN 55402
Tel.: (612) 340-5652
drysdale.michael@dorsey.com

Counsel for Petitioner
NorthWestern Corporation
d/b/a NorthWestern Energy

CERTIFICATE OF COMPLIANCE

Pursuant to Federal Rule of Appellate Procedure 32(g), I certify as follows.

1. Petitioners' Joint Reply complies with the word limit set in Federal Rule of Appellate Procedure 27(d)(2)(A) because, excluding the exempted parts, *see* Fed. R. App. P. 27(a)(2)(B), 32(f); D.C. Circ. R. 32(e)(1), this document contains **2,599** words according to the word count of the word-processing system used to prepare the document (Microsoft Word).

2. This document complies with Federal Rule of Appellate Procedure 32(a)(5) and (6) because it has been prepared using Microsoft Word in 14-point, proportionally spaced, Times New Roman font.

DATED: July 29, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

CERTIFICATE OF SERVICE

I certify that on July 29, 2024, the foregoing Joint Reply was served electronically on all registered counsel through the Court's CM/ECF system.

DATED: July 29, 2024

/s/ Joshua B. Frank

Joshua B. Frank
Counsel for Talen Montana, LLC

ORAL ARGUMENT NOT YET SCHEDULED

Nos. 24-1201 (consolidated with No. 24-1119)

In the United States Court of Appeals for the District of Columbia Circuit

AMERICA'S POWER
AND
ELECTRIC GENERATORS MATS COALITION,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

PETITIONERS' REPLY IN SUPPORT OF MOTION FOR STAY PENDING JUDICIAL REVIEW

Makram B. Jaber
Allison D. Wood
Aaron M. Flynn
MCGUIREWOODS LLP
888 16th Street N.W., Suite 500
Black Lives Matter Plaza
Washington, DC 20006
(202) 857-1700
mjaber@mcguirewoods.com

Counsel for Petitioners America's Power and Electric Generators MATS Coalition

TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES

Page(s)

CASES

STATUTES

REGULATIONS

OTHER AUTHORITY

GLOSSARY

Acronym	Meaning
2024 Technical Memo	EPA, *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo)* (Jan. 2024) (Docket ID EPA-HQ-OAR-2018-0794-6919), https://www.regulations.gov/document/EPA-HQ-OAR-2018-0794-6919
EGU	Electric generating units
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
fPM	Filterable Particulate Matter
HAP	Hazardous Air Pollutant
PM CEMS Memo	EPA, *PM CEMS Random Error Contribution by Emission Limit* (Mar. 22, 2023) (Docket ID EPA-HQ-OAR-2018-0794-5786), file:///C:/Users/mbjaber/Downloads/EPA-HQ-OAR-2018-0794-5786_attachment_7.pdf

INTRODUCTION

The Environmental Protection Agency ("EPA") refuses to learn the lesson of *Michigan*. The Supreme Court held that "[o]ne would not say that it is even rational … to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Michigan v.* EPA, 576 U.S. 743, 752 (2015). Yet, the Rule[1] imposes hundreds of millions of dollars of cost for trivial benefits because, for hazardous air pollutants ("HAPs"), EPA believes that Congress's standard is "[l]ess is better." EPA Rep. 1. EPA is wrong.

EPA's Rule rests on a deeply flawed evaluation that turns a blind eye to data EPA has (but refuses to consider), makes unsupported and unexplained assumptions, and ignores the reality EPA's other rules create. EPA responds by citing itself as support for its assumptions, vainly throwing spaghetti at the wall in the hope something will stick, and the Court will throw its hands up and defer to the "expert agency." But if the Court "endeavor[s]

[1] 89 Fed. Reg. 38,508 (May 7, 2024).

to consider thoroughly the claims" presented, even though "the volume and technical complexity of the material necessary for [its] review [could be] daunting…." *Sierra Club v. Costle*, 657 F.2d 298, 314-15 (D.C. Cir. 1981), it will realize there is no there there.

ARGUMENT

I. Petitioners Are Likely to Prevail on the Merits.

A. Imposing Exorbitant Costs for Trivial Benefits Is Irrational.

EPA starts by knocking down a strawman: "Movants' insistence that EPA cannot tighten standards found to have an ample margin of safety in the risk review" is meritless, EPA Resp. 13 (citing, first, Am.Power Mot. 5-9), because technology review under Section 7412(d)(6) and risk review under Section 7412(f)(2) are "separate and distinct," *id.* (citation omitted). Except Petitioners never said that. Petitioners argue that when the risk from *all* sources affected by a rulemaking is trivial—i.e., less than 1-in-1-million—*Michigan* commands it is irrational to impose hundreds of millions of dollars to reduce that trivial risk even further.

"Ample margin of safety" has a technical meaning that differs from *trivial* risk. Congress adopted into Section 7412(f)(2) EPA's pre-1990 "*Benzene* standard" interpretation, which "established a maximum excess risk of 100-in-one million" as providing the ample margin of safety. *See NRDC v. EPA*, 529 F.3d 1077, 1081-83 (D.C. Cir. 2008). Accordingly, the Rule found an ample margin of safety for oil-fired units, even though the risk from those units exceeded the trivial standard of 1-in-1-million (but was less than 100-in-1-million). *See* Am.Power Mot. 6. Petitioners do not argue reducing emissions from oil-fired units would not have been worthwhile just because an ample margin of safety exists. Rather, Petitioners argue the Rule is unlawful because the risk from all sources affected by it is trivial—less than 1-in-1-million, which is why an entire source category can be delisted from Section 7412 if its risk falls below that threshold. 42 U.S.C. §7412(c)(9). A Section 7412(d)(6) rule is *de facto* irrational when its only benefit lowers the risk below the level Congress found so trivial as to justify delisting the source category.

EPA's second overarching argument is, provided the risk is not zero, reducing HAPs is always worthwhile because Congress mandated "less is better." EPA Resp. 1, 33 (The "new standards' chief benefit—less air-toxics emissions—is the point of Section 7412.”). In *Michigan*, EPA argued it need not consider costs in listing powerplants under Section 7412(n)(1)(A) because Congress generally required listing decisions be based upon the “volume of pollution emitted.” 576 U.S. at 756-57. The Court rejected this “less is better” approach. This Court should too. If it is not “‘appropriate,’ to impose” large costs for minute benefits, *id.* at 752, then surely one cannot say that is “necessary,” 42 U.S.C. § 7412(d)(6).

Further, EPA protests, it did “consider” both costs and benefits, and “concluded that the rule is a ‘worthwhile’ exercise….” EPA Resp. 30. *Michigan*, however, requires more than acknowledging “the advantages and the disadvantages of agency decisions.” 576 U.S. at 753. *Michigan* requires “paying attention” by weighing costs against benefits, and reasoned decisionmaking requires some cogent *explanation* of *how* “the costs of its decision outweighed the benefits.” *Id.* at 750. Here, EPA nods towards the proposition that toxics generally (at some dose and exposure) are “associated with a variety of adverse effects,” 89 Fed. Reg. at 38,515, and then declares the Rule “a 'worthwhile' exercise" of its authority.[2] EPA Resp. 30. There is no weighing, much less explaining, how "the costs of its decision [are] outweighed [by] the benefits." *Michigan*, 576 U.S. at 750. That is arbitrary and capricious.

EPA's only cogent measure of benefit under Section 7412 is the amount of avoided risk. Although EPA did not quantify that either, its risk review assesses the residual risk from the units the Rule regulates—i.e., the maximum risk the Rule could avoid. But that maximum is 1 to 3 orders of magnitude *smaller* than the trivial-risk-level-equivalent. Am.Power Mot. 8-9. The Rule irrationally requires exorbitant costs for negligible benefits. It is unlawful. *See Michigan*, 576 U.S. at 750, 752. Petitioners are likely to prevail in the litigation; this Rule should therefore be stayed. *Ohio v. EPA*, 144 S.Ct. 2040, 2053 (2024).

---

[2] EPA's approach to weighing benefits and costs is reminiscent of a "Churchill Martini," "a glass of cold gin with a nod in the direction of France in lieu of vermouth." Tony Sachs, *History's Greatest Drunks: Winston Churchill*, YahooFinance (Aug. 17, 2016), https://finance.yahoo.com/news/history-greatest-drunks-winston-churchill-010000121.html.

B. The Rule Is Otherwise Arbitrary and Capricious.

1. The Rule Rests on a Deeply Flawed Technical Foundation.

EPA based the Rule's revised filterable particulate matter ("fPM") standard on a revised analysis just as unsupported and flawed as the proposal's irrationally truncated and arbitrary analysis. Am.Power Mot. 9-17. EPA argues the Rule fixed all the proposed analysis's flaws by considering more data points and relying on the average of a unit's fPM rate as a measure of what "the unit can consistently achieve." EPA Resp. 17-18. This average fPM rate is, indeed, the linchpin of EPA's analysis: (1) if this average is less than 0.010 lb/MMBtu, EPA assumes the unit "consistently achieves" it; (2) if the unit's average exceeds 0.010 lb/MMBtu *and* it previously "achieved" that rate at least once, then EPA assumes the unit will have to spend only $100,000 per year to meet the standard. 2024 Technical Memo at 5. The remaining units, which according to EPA never previously achieved 0.010 lb/MMBtu, will incur significant costs to upgrade or install controls. *Id.* at 6.

The Court should not be fooled by these technically complex-sounding assumptions; it's a sleight of hand. First, EPA bases its calculated average on whatever truncated dataset EPA arbitrarily selected (which differs from unit-to-unit), not the average of *all* 28 quarters of data EPA has. *See* 2024 Technical Memo, Attach. 1. EPA considered *only one single* quarter in roughly the last 28 quarters to characterize the performance of 43 units; *two* quarters for 135 units; *three* quarters for 13 units; and *four* quarters for 12 units. No engineering degree is required to recognize that performance during one to four quarters in the last 28 is not representative. Especially for units that did stack tests. For these units, when EPA looked at one quarter, it based the Rule on their performance in three one-hour runs—three hours—in the last 7-8 years (i.e., 3 out of 61,320-70,080 hours).

Moreover, an average cannot, in any rational world, show what a unit "can consistently achieve." Quite the opposite, as EPA concedes, "[o]f course, among units that averaged 0.010 lb/MMBtu or less, emissions at times exceeded that level." EPA Resp. 18. An average *never* shows what a unit "can consistently achieve." It necessarily demonstrates the unit sometimes achieved less and sometimes achieved more than the average. Undeterred, EPA discounts emissions variability:

> There was nothing special about 0.010 lb/MMBtu [when the standard was 0.030 lb/MMBtu], and one would not expect regulated units to try to keep their emissions below that level. … So the sporadic higher levels do not alter either the fact that regulated units could, using existing controls, average 0.010 lb/MMBtu, or the conclusion that the 0.010 lb/MMBtu standard is feasible.

Id.

How does EPA know that the measurements above 0.010 lb/MMBtu were "sporadic"? It does not. EPA has no idea, for it refused to consider *all* its data. And when EPA deigned to consider more than a few quarters, the exceedances become anything but sporadic. Coronado had a rate exceeding 0.010 lb/MMBtu in 21 out of 31 quarters. 2024 Technical Memo, Attach. 1. Two thirds of the quarters considered is not "sporadic." Or take Fort Martin in West Virginia. EPA considered stack tests for only two quarters: One measured a rate of 0.00691 lb/MMBtu, well below the revised standard, and the second a rate of 0.01549, well above the revised standard. *Id.* Yet EPA's methodology classified this unit, which failed to meet the revised standard half the time, as "consistently meet[ing]" it because EPA calculated an *average* rate less than 0.010 lb/MMBtu.

This cannot stand and cannot work. A standard must be met every day (on a 30-day rolling basis) not on "average." A standard must be achievable every day, not sometimes. EPA did not analyze—and thus has no idea—*why* Coronado and similar units emitted more than 0.010 lb/MMBtu some of time. Was it inherent equipment and conditions variability, fuel variability, or other variability outside the control of the operator (making that standard unachievable for that quarter)? EPA does not know. EPA's "fail[ure] to analyze this important aspect of the problem" renders the rule unlawful. *Motor Vehicle Mfrs. Ass'n v. State Farm Auto Mut. Ins. Co.*, 463 U.S. 29, 43 (1983).

The Rule is arbitrary and capricious because this fundamental assumption underpinning the Rule is not just unjustified and unexplained, *see U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 650 (D.C. Cir. 2016), it is irrational and contradicted by the empirical data. *See Ohio*, 144 S.Ct. at 2054; *State Farm*, 463 U.S. at 43.

2. EPA's Refusal to Account for a Compliance Margin is Arbitrary.

To cut through the fog of the half-baked, post-hoc rationalizations EPA proffers in its response, it would be useful to step back and lay out what a compliance margin is and why it matters. A compliance margin is a buffer that operators seek to maintain to allow for hiccups and variability. Thus, when a standard is set at 0.010 lb/MMBtu, no engineer designs the control equipment to achieve, and no operator would operate at, exactly 0.010 lb/MMBtu. Doing so would be a recipe for a Clean Air Act violation. The inherent performance variability present in all control equipment informs the magnitude of the needed compliance margin. Here, given the extremely low standard and given real-life variability, the compliance margin would likely be 50%, as EPA recognized. *See* PM CEMS Memo at 2. This effectively means the controls are designed and operated to hit a target rate of 0.005 lb/MMBtu.

Thus, as a practical matter, accounting for a compliance margin leads to an *effective* standard lower than the standard ultimately selected. In any analysis that bases a standard on the units' *actual* past performance, accounting for a compliance margin is crucial and determinative of (1) the number of units needing upgrades or new controls to meet the standard and, therefore, (2) the rule's actual costs.

Here, EPA's analysis accounts for *zero* compliance margin—it assumes a unit that (purportedly) "consistently met" 0.010 lb/MMBtu (the Gavin unit is an example, *see* 2024 Technical Memo, Attach. 1) based on whatever dataset EPA chose would have to do nothing to comply with the Rule. A unit that "consistently met" 0.015 lb/MMBtu (the Harrison units are good examples, *see id.*) will have to reduce its rate by 33% (from 0.015 to 0.010), so it will need a "typical ESP upgrade" at a cost of $40/kw. *Id*. But when EPA, for the sake of argument, performed an analysis with a 20% compliance margin, it used an *effective* standard of 0.008 lb/MMBtu—and thus determined only those units that "consistently met" 0.008 lb/MMBtu need not do anything to meet the new standard of 0.010 lb/MMBtu (with a 20% compliance margin). So Gavin, which previously had to do nothing, now must undergo a typical ESP upgrade to achieve the 0.008 lb/MMBtu that incorporates the 20% compliance margin. Harrison, which previously needed only an ESP upgrade, now must do an "ESP rebuild" at twice the cost ($80/kw) to meet the standard with a 20% compliance margin.

Finally, EPA's alternative standard of 0.060 lb/MMBtu is equivalent to a standard of 0.010 lb/MMBtu reduced by a 40% compliance margin. *See* Am.Power Mot. 21-22. This alternative's analysis yielded a cost-effectiveness of $17,500,000/ton HAPs removed—about a 67% increase over EPA's cost-effectiveness based on standard with zero-compliance margin. 2024 Technical Memo at 16-17, Table 4.

The Response claims the revised "standard accounts for compliance margins." EPA Resp. 23. Not so. First, EPA conceded in the Rule its main analysis did not account for compliance margin when it (1) tried to defend that in the preamble and (2) did an alternative, truncated analysis assuming a 20% compliance margin to argue it would not have changed its conclusion. *See* Am.Power Mot. 19-21.

Second, counsel's post-hoc rationalizations should be summarily rejected, *see State Farm*, 463 U.S. at 43, and are incorrect anyway. The Response claims EPA accounted for compliance margin, first "by setting the emission limit above what most coal-fired units were emitting on average." EPA Resp. 23. EPA did not say that in the Rule, when it responded to comments relating to compliance margin. That is because it is a *non sequitur*. As explained above, accounting for a compliance margin results in an *effective* standard lower than the proposed standard.

Counsel continues, "The other place that the standard builds in a margin is on the compliance side. It assesses a given facility's compliance using 30-day rolling averages." *Id.* at 23-24; *see also* ENGOs Resp. 12. Again, EPA did not say that in the rulemaking. For good reason: that too is a *non sequitur.* EPA based its analysis on 30-day rolling values; the issue is whether EPA should have accounted for a compliance margin *within* the 30-day rolling values—a margin that accounts for the variability that occurs in 30-day rolling values, not daily values.

3. EPA's Failure to Account for the Shortened Life of the Vast Majority of Coal-Fired EGUs Ignores an Important Aspect of the Problem.

EPA defends its refusal to account for the shortened life of the vast majority of coal-fired units because of the simultaneously-issued GHG Rule, 89 Fed. Reg. 39,798 (May 9, 2024), by blithely responding: "nothing in that rule compels retirement" and citing its own opposition to a motion to stay the GHG Rule as support. EPA Resp. 20. That is too cute by half. Petitioners in that case submitted dozens of sworn declarations attesting the *only* realistic option for coal-fired units to comply with the GHG Rule is to retire by 2032. *See, e.g., West Virginia v. EPA*, No. 24-1120, (D.C. Cir.) ECF#2056364, ECF#2054191; *see also* Talen Mot., ECF#2062093, Ex. 1 (Lebsack Decl.) ¶¶41–44.

CONCLUSION

For these reasons and those in the Stay Motions, Petitioners are likely to succeed on the merits. For the reasons in our Stay Motion and the stay motions of fellow Petitioners, supported by multiple companies' declarations, including members of Movants, and their replies in support, Petitioners will suffer irreparable harm absent a stay. ECF#2058570; ECF#2061137; ECF#2062093; ECF#2062097; ECF#2063292. A stay will not harm the public, and the public interest strongly favors a stay. *Id.*

This Court should stay EPA's Rule.

Dated: July 29, 2024

Respectfully submitted,

/s/ Makram B. Jaber

Makram B. Jaber
Allison D. Wood
Aaron M. Flynn
McGuire Woods LLP
888 16th Street N.W., Suite 500
Black Lives Matter Plaza
Washington, DC 20006
(202) 857-1700
mjaber@mcguirewoods.com
awood@mcguirewoods.com
aflynn@mcguirewoods.com

Counsel for Petitioners America's Power and Electric Generators MATS Coalition

Certificate of Compliance

Pursuant to Fed. R. App. P. 32(a)(5), (6) and D.C. Circuit Rules 27(a)(2), I certify that: This document complies with the type-volume limitations of Fed. R. App. P. 27(d)(2)(A) because it contains 2,600 words, excluding the parts of the motion exempted by Fed. R. App. P. 32(f) and 27(a)(2)(B). This document complies with the typeface and type style requirements of Fed. R. App. P. 27(d)(1)(E) because it has been prepared in a proportionately spaced typeface using Microsoft Word version 16.61 Palatino Linotype 14-point font.

/s/ Makram B. Jaber
Makram B. Jaber

CERTIFICATE OF SERVICE

I hereby certify that on this 29th day of July 2024, I filed the foregoing motion with the Clerk of the Court using the CM/ECF System, which will send notice of such filing to all registered CM/ECF users.

/s/ Makram B. Jaber
Makram B. Jaber

APPENDIX F

SELECT DECLARATIONS FILED IN THE D.C. CIRCUIT CASE

DECLARATION OF DALE E. LEBSACK, JR.
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, Dale E. Lebsack, Jr. hereby declare and state under penalty of perjury that the following is true and correct to the best of my knowledge and is based on my personal knowledge or information available to me in the performance of my official duties.

INTRODUCTION

1. My name is Dale E. Lebsack, Jr., and my business address is 1725 Hughes Landing Boulevard, Suite 800, The Woodlands, Texas 77380. I am over the age of 18. I have personal knowledge of the subject matter and am competent to testify concerning the matters in this Declaration.

2. I currently work as President of Talen Montana, LLC ("Talen Montana") and as Chief Fossil Officer for Talen Energy Corporation ("Talen Energy"), its ultimate parent company. As President of Talen Montana, I am responsible for the day-to-day executive management of Talen Montana's business, properties, and operations.

3. I have worked for Talen Energy and its predecessor companies for over 19 years. Over that time, I have had roles of increasing responsibility in multiple aspects of fossil power generation, including asset management, plant operations, engineering, environmental, health and safety, and project development. This

Declaration is based on my personal knowledge as President of Talen Montana and Chief Fossil Officer of Talen Energy, and analyses conducted by my colleagues.

4. I am submitting this Declaration in support of Petitioners Talen Montana and NorthWestern Corporation d/b/a NorthWestern Energy's Joint Motion to Stay the U.S. Environmental Protection Agency's ("EPA" or "Agency") final rule titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," commonly referred to as the Mercury and Air Toxics Standards ("MATS"). 89 Fed. Reg. 38508 (May 7, 2024) ("MATS Final Rule").

5. I am familiar with Talen Montana's operations, including generation, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the MATS Final Rule, and I am familiar with how the MATS Final Rule will affect Talen Montana. Additionally, I am familiar with EPA's greenhouse gas rule, 89 Fed. Reg. 39798 (May 9, 2024) ("GHG Rule"),[1] as described below.

6. Talen Montana has economic interests in coal-fired units that will be subject to the MATS Final Rule.

[1] *See* 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).

7. Talen Montana is the operator of Units 3 and 4 at the Colstrip Steam Electric Station, commonly referred to as Colstrip Power Plant ("Colstrip"), in Rosebud County, Montana. Talen Montana also has a 15 percent economic interest in these units, which currently consist of two active coal-fired generating units capable of producing up to 1,480 net MW of electricity that have been operating for approximately 38 years.

8. Each of the units has approximately 740 MW of net generating capacity, and the adjacent Rosebud coal mine supplies Colstrip's low-sulfur subbituminous coal. Units 3 and 4 are the only remaining active units at Colstrip, as Units 1 and 2 recently retired in 2020. Units 3 and 4 have a useful life of at least another two decades, provided investments continue to be made for equipment maintenance and replacement as necessary.

9. Colstrip is one of the largest coal-fired electric generating facilities west of the Mississippi River, supplying electricity throughout Montana and the Pacific Northwest. Colstrip plays an integral role in maintaining operation of the NorthWestern Balancing Authority in Montana, especially during peak electricity demand events.

10. The MATS Final Rule sets forth aggressive compliance timelines for demonstration of compliance with EPA's new and more stringent filterable particulate matter ("fPM") emission limit—requiring that these upgrades be made at

Colstrip by July 8, 2027. As discussed below, compliance with the MATS Final Rule is anticipated to cost more than $350 million at Colstrip, with $15 million in additional annual operating costs.

Summary of Key Points

11. In this Declaration, I make the following points:

a. The MATS Final Rule requires Talen Montana and the Colstrip owners to make immediate decisions that will either lead to the installation of extremely costly pollution controls on Colstrip or a premature retirement. If the MATS Final Rule is not stayed, this irreversible decision will be made prior to the conclusion of this litigation. Massive costs for compliance with the MATS Final Rule will be expended unnecessarily if the MATS Final Rule is not upheld on appeal. Moreover, the consequences of early closure of Colstrip on Montana and its local economy are known, measurable, and severe.

b. Colstrip's six owners are split between two intrinsically different business models (i.e., utilities regulated by different state commissions, versus, in Talen Montana's case, a merchant generator), which impacts their business objectives, financial priorities, and motivations for evaluating whether to support installing mandatory but costly controls under the MATS Final Rule.

c. Each of Colstrip's six owners have differing regulatory landscapes and state policy considerations (i.e., owners situated in states that want to minimize coal-fired power versus those that are not), which further impacts their unique priorities and considerations for deciding whether to install costly controls under the MATS Final Rule.

d. The differing positions among Colstrip's owners are significant, suggesting that compliance with the MATS Final Rule will be extremely contentious absent a stay, while a stay would allow for rational decision-making about Colstrip's future.

e. Absent a stay, installation of new emissions control systems will be extremely expensive—and potentially cost prohibitive—for Colstrip. Such high costs may lead to the premature retirement of Colstrip by the MATS Final Rule's compliance date of July 8, 2027, with a decision to retire made long before litigation over the rule is completed.

f. EPA's GHG Rule, if not overturned, will force closure of Colstrip by the end of 2031, significantly limiting the time to recoup investments to comply with the MATS Final Rule.

g. Absent a stay, it is almost certain that significant time and resources will be dedicated to addressing disputes over the expenditure of funds for compliance with the MATS Final Rule.

h. Absent a stay, compliance efforts with the MATS Final Rule would need to begin essentially immediately—extremely challenging given

Colstrip's unique ownership structure. Talen Montana has already begun the process of expending funds to study the compliance options and timelines, and millions of dollars will be required to continue engineering and design efforts later this year, ramping up further next year as construction would need to begin.

i. Per the above points, Talen Montana will directly experience material irreparable harm.

These points are discussed in further detail in the remainder of this Declaration.

TALEN MONTANA AND COLSTRIP OWNERSHIP

12. Talen Energy is an independent power producer that owns and operates approximately 10.7 gigawatts of power infrastructure in the United States. Talen Energy (through its subsidiaries) produces and sells electricity, capacity, and ancillary services into wholesale U.S. power markets, including PJM Interconnection, LLC ("PJM") and the Western Electricity Coordinating Council ("WECC"), with Talen Energy's generation fleet principally located in the Mid-Atlantic and Montana. Talen Energy's generation fleet includes wholly owned and partially owned assets that use nuclear, coal, oil, and natural gas as fuels.

13. Talen Montana is one of six owners, and is the operator, of Colstrip.

Each of Colstrip's six owners have differing business models, which impacts their priorities and considerations for deciding whether to install required costly controls under the MATS Final Rule and will complicate and lengthen the decision-making process.

14. Unlike traditional regulated utilities,[2] which have a process for recovering certain costs through electricity rates, Talen Montana is a "merchant power producer." Talen Montana sells power from Colstrip into the wholesale market.

15. Thus, Talen Montana has no "captive ratepayer." While regulated utilities have a set customer base, Talen Montana does not, as its wholesale customers have access to an open market. The market and its participants can always favor a different electricity producer if Talen Montana's power production costs are too high. Additionally, unlike regulated utilities that may be able to recover capital expenditures for new pollution controls through rates, Talen Montana cannot pass on such costs to its customers through rate adjustments.

16. Rather, Talen Montana is subject to market rates for its electricity and must rely on those market prices to pay for any new capital expenditures. Such prices may not reflect the additional costs incurred. The need for substantial upfront investment can put strains on financial resources and expose the company to risks.

---

[2] Utilities, such as investor-owned utilities or public utilities, operate under a highly-regulated framework where the utility company owns the generation and transmission necessary to serve its end-use customers and manages the system operations to serve its customers. These utilities are regulated by state utility commissions. Such regulation typically includes the setting of rates that are intended to allow the utility to recover a reasonable rate of return on its investments. Thus, a regulated utility may (or may not) be able to recover through rates the costs for installing facility upgrades (such as pollution control equipment under the MATS Final Rule), dependent on the approval of state regulators.

17. Market prices for electricity may be volatile and are driven by factors such as supply and demand, fuel costs, and weather conditions. When electricity prices are low, it is more challenging to recover the costs of new capital investments like pollution controls. Because the company must absorb the financial burden of these capital expenditures, with no certain ability to pass the costs onto consumers, this can erode or eliminate profit margins.

18. Additionally, given that market prices for electricity fluctuate and are difficult to predict into the future, this complicates Talen Montana's ability to manage for and recoup investments in pollution control equipment, which in turn makes it difficult to plan for long-term investments.

19. Thus, while Talen Montana must undertake an economic analysis of the risks of installing controls in light of predicted market sales of wholesale power in the period after installation of controls, the other owners must deal with their regulatory commissions to determine whether such costs would be permitted to be passed on to end users, and some owners may choose not to undertake that process at all. In sum, the different structure of the Colstrip owners means that there are different financial motivations, risks, and other considerations for deciding whether to install costly controls that will inevitably lead to delays in the decision-making process.

Each of Colstrip's six owners have differing ownership interests and state regulatory considerations, which further impacts their unique

priorities and considerations for deciding whether to install required costly controls under the MATS Final Rule.

20. As noted above, Talen Montana is one of six owners, and each of these owners have different ownership interests. Colstrip Units 3 and 4 are co-owned by Avista Corporation ("Avista"), Portland General Electric Company, Inc. ("PGE"), Puget Sound Energy, Inc. ("PSE"), PacifiCorp (collectively, the "PNW Owners"), NorthWestern Corporation ("NorthWestern"), and Talen Montana.

21. All owners other than Talen Montana are traditional utilities governed by a state commission. Some are subject to regulations in multiple states. For example, laws passed by Oregon and Washington apply to the PNW Owners.

a. Oregon passed a statute in 2016 that bars utilities from supplying coal-fired electricity to certain Oregon retail customers after January 1, 2030.[3] Washington followed suit in 2019 by passing a statute that will impose substantial penalties on utilities who provide coal-fired electricity to certain Washington retail customers after December 31, 2025.[4] With respect to the Washington statute, the PNW Owners serving retail customers in Washington remain free to use coal-fired electricity subject to the statutory penalties. Oregon and Washington's clean energy laws discussed above may limit or discourage the PNW Owners' ability to use

[3] Or. Rev. Stat. §§ 757.518 and .519.

[4] Wash. Rev. Code §§ 19.405.030(1)(a), (4) and 19.405.090(1)(a)(i).

Colstrip to serve customers in Washington and Oregon, with those laws becoming effective in 2026 in Washington and 2030 in Oregon.

b. Unlike the PNW Owners, Talen Montana and NorthWestern are not subject to these regulations promulgated by the applicable utility commissions in Oregon and Washington.

22. The Colstrip units are governed by a 1981 ownership agreement. Each Colstrip Owner's respective ownership interest in Colstrip is as follows:

Owner	Unit 3	Unit 4
Avista	15%	15%
NorthWestern	--	30%
PacifiCorp	10%	10%
PGE	20%	20%
PSE	25%	25%
Talen Montana	30%	--

NorthWestern has agreed to acquire Avista's share as of January 1, 2026.[5]

23. Each of the regulated utility owners will evaluate compliance with the MATS Final Rule differently, largely because of their separate state's commissions and stakeholders and regulatory frameworks, i.e., laws in those states regarding use of electricity from coal fired power plants. Some owners, like NorthWestern, must engage with their respective public utility commissions to determine what action would have the least impact on grid reliability and electricity costs to customers,

[5] *See* Declaration by John D. Hines ("NorthWestern Decl.") at ¶¶ 8, 37, 68.

including whether to install controls (which could require extended outages for installation), or whether to seek early retirement and instead seek replacement generation.[6]

24. From Talen Montana's perspective, however, there is no current planned retirement date for Colstrip. And as a merchant power generator (described above), Talen Montana is not subject to any regulation by a state commission. Talen Montana's position on compliance with the MATS Final Rule will largely be driven by economic factors.

The differing positions among Colstrip's six owners are deep-rooted, suggesting that compliance with the MATS Final Rule will be extremely contentious absent a stay, whereas a stay would allow for rational decision-making about Colstrip's future.

25. The divergent interests of certain PNW Owners, on the one hand, and NorthWestern and Talen Montana, on the other hand, have led to disputes regarding the future of Colstrip and the owners' ability to close (or not close) the plant under the ownership agreement.[7] According to one filing, underlying disputes between

[6] *See id.* ¶¶ 18–32 (explaining that the MATS Final Rule will materially increase electricity-delivery costs in Montana, and it is uncertain whether those will be recoverable in electrical rates, and that NorthWestern anticipates significant resistance from the Montana Public Service Commission to the MATS Final Rule-based rate increases "given the magnitude of the costs, the short useful life of the controls, and the EPA's own findings that additional controls are not necessary to protect human health").

[7] *See* Decl. of Ronald J. Roberts in supp. of PSE Mot. for Relief from Automatic Stay, at 20, *In re Talen Energy Supply, LLC et al*., No. 22-90054 (Bankr. S.D. Tex.).

Talen Montana and the PNW Owners regarding how and when to retire the remaining Colstrip units "originated over a decade and a half ago."[8]

26. Colstrip's owners continue to have divergent constraints when it comes to long-term planning for Colstrip's future. In fact, this very issue—Colstrip's retirement—has been litigated in a years-long dispute that has resulted in litigation and arbitration, and has even resulted in legislation passed by the Montana legislature.[9] The owners have long had different priorities regarding Colstrip's future and long-term planning, suggesting that issues regarding MATS Final Rule compliance will be contentious.

27. In addition to the impacts of the MATS Final Rule in the context of its 15% economic interest in Colstrip, Talen Montana will be further impacted by disputes among the owners regarding the MATS Final Rule due to its role as Colstrip's operator. As Colstrip's operator, Talen Montana is the "agent for and on

---

[8] *See* Debtors' Opp'n to Mot., at 7, *In re Talen Energy Supply, LLC et al*., No. 22-90054 (Bankr. S.D. Tex.).

[9] *See, e.g., See Portland Gen. Elec. Co. v. Northwestern Corp.,* No. 1:21-cv-0047-BLG-SPW-KLD (D. Mont.). Senate Bill 266 applied to Colstrip's owners and made it a violation of law to fail or refuse to fund its share of operating costs, or to bring about permanent closure of a generating facility without seeking and obtaining consent of all owners. S.B. 266, § 2(2)(a), (b), 67th Leg., Reg. Sess. (Mont. 2021). Senate Bill 265 mandated three arbitrators unless all parties agreed to a single arbitrator. S.B. 265, § 1, 67th Leg., Reg. Sess. (Mont. 2021).

behalf of the Owners" and must construct, operate, and maintain Colstrip in accordance with Prudent Utility Practice.[10]

28. Given the differing business models and competing state regulatory considerations among the owners, Talen Montana—as operator—finds itself stuck in the middle from an economic perspective because, however Talen Montana interprets its duty as operator in this matter, it is likely to antagonize one or more of its co-owners. Additionally, as Colstrip operator Talen Montana has no independent source of funding. Talen Montana has only what is advanced or recovered from the

[10] This is stated in Section 3(b) of the Colstrip Units 3& 4 Ownership and Operation Agreement ("O&O Agreement"). In O&O Agreement Section 1(r):

> "Prudent Utility Practice" at any particular time means either any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practice shall apply not only to functional parts of the Project, but also to appropriate structures, landscaping, painting, signs, lighting, other facilities and public relations programs, including recreational facilities, and any other programs or facilities, reasonably designed to promote public enjoyment, understanding and acceptance of the Project. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts. Prudent Utility Practice shall also include those practices, methods and acts that are required by applicable laws and final orders or regulations of regulatory agencies having jurisdiction.

other owners for operations, maintenance, and capital expenditures at Colstrip.[11] Hence, Talen Montana may bear the financial risk if a Colstrip owner chooses not to reimburse costs related to compliance with the MATS Final Rule.

29. The owners will always have disparate positions about installing costly controls to comply with the MATS Final Rule, which likely will lead to further contention between the owners if Talen Montana, NorthWestern, or others seek to install controls. Disputes between the owners have already begun to unfold over the costs of the preliminary analysis of possible compliance options.

30. Further disputes would at least be delayed and possibly rendered unnecessary if there is a stay of the rule.

31. Without a stay, existing disputes will almost certainly intensify and interfere with the ability to reach a timely consensus on the retirement of Units 3 and 4, burdening the companies' resources.

CONTROL REQUIREMENTS, IRRECOVERABLE COSTS, AND IMPLICATIONS

Absent a stay, installation of new emissions control systems will be extremely expensive—and potentially cost prohibitive—for Colstrip.

32. The MATS Final Rule may force Talen Montana to make a massive investment in new emissions control technologies that is difficult to justify even when considered without reference to other contemporaneous EPA rulemakings

[11] O&O Agreement Section 3(b), Articles 6–11.

(e.g., the GHG Rule). As noted above, the MATS Final Rule significantly tightens the surrogate fPM standard for demonstrating compliance with the emissions limits for non-mercury ("non-HG") metal hazardous air pollutants ("HAPs") from 0.03 lb/MMBtu to 0.010 lb/MMBtu, among other related requirements.

33. Colstrip cannot comply with the more stringent fPM limits in the MATS Final Rule with its current pollution control equipment. Colstrip must undertake a massive and complex construction project to install new controls—either fabric filters, known as baghouses, or electrostatic precipitators ("ESPs")—to come into compliance with the MATS Final Rule. Installation of these new emissions control systems will be extremely expensive—and potentially cost prohibitive—for Colstrip. If deemed cost prohibitive, the MATS Final Rule would require Colstrip to prematurely retire by the rule's compliance deadline of July 8, 2027, approximately three years from now. The decision to retire (or to install controls) would be made long before litigation over the MATS Final Rule is concluded.

34. Based on the latest information, the MATS Final Rule will require expenditures of over $350 million to install new fabric filters or ESPs, with the most likely option the installation of fabric filters between the plant's flue gas reheat system and the stack. In addition to the capital expenditure, the annual operation and maintenance cost is estimated to be approximately $15 million annually. *See*

Burns & McDonnell, *Colstrip Particulate Matter Control Cost Evaluation – Final* (Apr. 2024) (select excerpt included as Attachment A to this Declaration). Talen Montana is continuing to work on cost estimates and preliminary engineering on the pollution control equipment necessary to comply with the MATS Final Rule.

Absent a stay, it is almost certain that significant time and resources will be dedicated to addressing disputes over the expenditure of funds for compliance with the MATS Final Rule.

35. It is anticipated that the project to install new baghouses would take 36–42 months (i.e., three years minimum) to complete. Given that timeline, preliminary investigation and engineering work must begin the summer of 2024 (following contracting for such work) with detailed engineering and design in the fall of 2024. If approved, on-site construction work, such as laying foundations, would begin in spring of 2025—but federal permitting hurdles, environmental reviews, and potential challenges (e.g., by environmental organizations) could cause project delays.

36. Work in the balance of 2024 is expected to cost millions, and by the end of the first quarter of 2025, material purchasing will begin and multiple contract awards will ramp up commitments and spending rapidly on a $350 million project.

37. Given the anticipated timeframe for engineering and construction, even if the project could begin in the fall of 2024, it will be a challenge to complete by the July 8, 2027 compliance deadline, and may still be tight for a compliance even

if granted a one-year deadline extension under the rule. Schedules continue to slip due to supply chain disruptions and material and labor shortages.

38. Given these aggressive time frames, the MATS Final Rule affords Talen Montana no time to wait before beginning efforts to comply with the rule. Absent a stay, Talen Montana must start immediately. Accordingly, the MATS Final Rule requires that Talen Montana and the other five Colstrip owners decide in a short timeframe whether to go down a path that will lead to the commitment of hundreds of millions of dollars on new pollution control equipment or a premature retirement.

39. Importantly, any decision to proceed with the project would most likely be made by the Colstrip owners acting through the Project Committee established in their ownership agreement. As noted above, disagreements between the owners about compliance expenses could lead to disputes under the ownership agreement or otherwise. Without a stay, significant time and resources will be devoted to these potential disputes. Moreover, given the tight compliance schedule noted above, Talen Montana, as Colstrip operator, and possibly others, could face the prospect of having to spend hundreds of millions of dollars in compliance costs with its ability to recover those costs from the other owners in dispute.

EPA's GHG Rule significantly limits the time to recoup investments to comply with the MATS Final Rule.

40. Talen Montana, as a merchant generator, must consider how much time is available to recoup the costs of the investment (i.e., how long can the unit operate after installation of controls to pay for those controls) when deciding whether to invest in additional pollution control equipment or to retire the units (equipment lifespan and recoupment time is also a relevant factor for regulated utilities).

41. While Colstrip has no set retirement date, EPA's concurrent finalization of the GHG Rule under Clean Air Act Section 111(d) raises the stakes for Talen Montana because it significantly limits the time to recoup investments required to comply with the MATS Final Rule.

42. Under the GHG Rule, Colstrip can only operate beyond December 31, 2031, if it co-fires with natural gas before 2030 or installs carbon capture and sequestration ("CCS") before 2032.

43. As I set forth in my declaration in support of a stay motion in the GHG Rule (included as Attachment B to this Declaration), Colstrip cannot install CCS before 2032 or co-fire natural gas before 2030. This means that to comply with the GHG Rule (if upheld on appeal), it must permanently cease operation by the end of 2031.

44. As a result, accounting for the interaction of the Final MATS Rule and the GHG Rule, Talen Montana would have only from July 8, 2027 (or later if controls take longer to install, which is certainly possible) through the end of 2031

to recoup its share of the massive costs involved in MATS Final Rule compliance. Again, as a merchant generator, Talen Montana has no method to recoup these costs aside from generating revenue through the sale of power on the wholesale market.

45. The annualized costs of those expenditures, when spread over only approximately four years of operation after installation (or even fewer, if the operational date of controls is later), are staggering. Assuming 4.5 years of operation after installation of controls, the annualized capital costs would be approximately $109 million/year with the same discount rate assumptions made by EPA; if controls are installed subject to a one-year extension, the annualized capital costs would be approximately $133 million/year.

46. Given the volatile nature of wholesale power prices, it is highly uncertain whether the revenues available to Talen Montana in that four-year period will be enough for it to recoup its costs. While wholesale power prices in the Pacific Northwest are robust at present, should they revert to levels experienced as recently as 2020, Talen Montana will struggle to generate a profit on its share of Colstrip even before the hundreds of millions of dollars in compliance-related capital expenditures and millions of dollars per year in additional operating costs. The level of annualized costs to comply with the MATS Final Rule may be cost prohibitive and lead to a premature retirement of Colstrip.

47. In addition to depending on wholesale power prices to remain robust during the four-year period, Talen Montana's ability to recoup its investment is dependent on Colstrip's ability to operate during that timeframe. The complex power generation equipment used at Colstrip units will need to be offline for maintenance from time-to-time. Should those maintenance outages extend beyond anticipated durations, or should they occur during periods of high prices, Talen Montana could miss out on the revenues necessary to recover its investment. The relatively short recovery period of only four years exacerbates this operational risk.

48. Additionally, the cost to achieve a small incremental improvement in fPM removed is enormous. Colstrip already achieves 99.6 percent reduction of fPM with its existing wet venturi scrubbers.[12] The MATS Final Rule would require

[12] Since Colstrip Units 3 and 4 began commercial operations in the mid-1980s, Colstrip has continuously improved its methods for controlling air pollution. Colstrip has typically been able to remain below the current MATS limit of 0.030 lb/MMBtu of fPM. Since 2018, Colstrip has hired consultants and engineers to explore ways to further enhance the efficiencies of the venturi wet scrubbers. This work has made the venturi wet scrubber emissions more stable. Additionally, Colstrip implemented additional measures to address combustion conditions to help ensure that combustion of the coal occurs in a manner that prevents the formation of small fly ash particles that are difficult to remove in the wet venturi scrubbers. Together, these and many other comprehensive efforts reflect upgrades available to be implemented to the Colstrip scrubber/combustion process to reduce fPM, which has enabled Colstrip since 2018 to achieve consistent compliance with the current 0.030 lb/MMBtu fPM limit with an adequate compliance margin. In 2022, based on stack tests, Colstrip's two units combined achieved approximately 0.022 lb/MMBTU fPM on an annual basis—well below EPA's limit prior to the promulgation of the MATS Final Rule.

Colstrip to install an additional level of fPM control, at a cost exceeding $350 million, to further reduce fPM control from 99.6 percent to approximately 99.8 percent.

49. Moreover, the interaction of the MATS Final Rule with the GHG Rule and appellate challenges to those rules injects significant regulatory uncertainty into Talen Montana's planning process. The interaction between these rules forces Talen Montana and its co-owners to make immediate and consequential decisions about Colstrip's future, all of which will have ramifications not just for Talen Montana, but for Colstrip, the State of Montana, its citizens, and beyond. This decisional uncertainty inflicts immediate significant harm on Talen Montana, especially given its role as Colstrip operator, and could be avoided with a stay of the Final MATS Rule.

50. With a stay in place, Talen Montana would be able to operate from a set understanding, instead of absolute uncertainty, leading to rational decision-making about Colstrip's future with Colstrip's other owners.

TALEN MONTANA'S IMMEDIATE, IRREPARABLE HARMS

Absent a stay, compliance efforts with the MATS Final Rule would need to begin essentially immediately, which would be extremely challenging given Colstrip's unique ownership structure.

51. Absent a judicial stay, Talen Montana would be immediately and irreparably harmed for at least two reasons. First, absent a stay, compliance efforts

with the MATS Final Rule would need to begin immediately. Indeed, Talen Montana has already begun the process of expending funds to study the compliance options and timelines, and millions of dollars will be required to continue engineering and design efforts later this year. Second, these compliance efforts would involve a significant ramp-up in resources (i.e., time, effort, and coordination) this year, leading to major construction activities beginning by Spring of 2025, all of which might prove unnecessary and unrecoverable if the MATS Final Rule is overturned on appeal.

52. These decisions have far-reaching implications on Colstrip, Talen Montana, and beyond.

53. Regardless of Talen Montana's own decision-making process, Talen Montana must coordinate with the other five Colstrip owners with disparate ownership interests. As described above, several of Colstrip's owners likely would not favor investments to comply with the MATS Final Rule; and disputes amongst the owners are likely in the near future absent a stay. As Colstrip operator, Talen Montana will not only be harmed by the costs of contesting the dispute among the owners, but could also face the prospect of having to pay significant costs for complying with the MATS Final Rule without any certainty that Talen Montana can recover those costs.

54. Additionally, litigating the MATS Final Rule in a normal course would likely take a minimum of two to three years. Talen Montana and the Colstrip owners must make immediate and consequential decisions about Colstrip's future, with ramifications for Talen Montana, Colstrip, the State of Montana, its citizens, and beyond. These decisions must be made in the face of significant uncertainty over the Final MATS Rule (and the GHG Rule) given ongoing litigation. As described above, this decision uncertainty inflicts immediate significant harm on Talen Montana. If the MATS Final Rule is not stayed, yet is ultimately reversed on appeal, Talen Montana will have suffered the irreversible harm of either closing the plant prematurely or spending its share of hundreds of millions of dollars on unnecessary controls, by the time the legality of the MATS Final Rule is determined.

The consequences of early closure of Colstrip on Montana and its local economy are severe.

55. Early closure of Colstrip would cause significant economic harms to the local area and Montana.

56. Colstrip is pivotal to Montana. Colstrip is a primary source of safe, reliable electricity for Montanans and provides significant economic benefits in the form of direct and indirect jobs, tax revenue, and economic development. The impact of the MATS Final Rule, should it result in the premature closure of Colstrip, will extend well beyond the plant, the Rosebud mine, and the local community.

Early closure would put Montana's electric reliability at risk and could negatively affect Montana's economy.

57. Aside from its role in providing affordable, reliable electricity, Colstrip makes significant economic contributions to the local, county, and state economy.

58. A 2024 study conducted by Dr. Patrick M. Barkey, Ph.D. on the potential economic implications of the MATS Final Rule for Montana's economy (included as Attachment C to this Declaration) found that, if Colstrip were to retire prematurely, in 2028 alone (the first full year of closure for the mine and Colstrip):

a. Montana would have more than 3,000 fewer year-round jobs.

b. Montana households would experience more than $240 million lost income (more than $203 million disposable, after-tax income).

c. Montana would lose over a billion dollars in economic output, generally defined as gross receipts of business and non-business organizations. Of note, this revenue loss is felt by every industry in the economy.

d. Montana would lose more than $102 million in State tax revenue.

59. The study's conclusions are corroborated by other key financial measures which I am familiar with.

60. Colstrip is a large part of Montana's tax base. Colstrip pays approximately $60 million in state, county, and local taxes annually, accounting for 90 percent of municipal and 75 percent of county tax revenue. Colstrip's owners

pay an average of $70 million per year in taxes just for the fuel component of Colstrip, which includes Federal and State Royalties and Severance Tax.

61. Colstrip's owners pay approximately $1.025 million per year directly to the Montana Department of Environmental Quality.

62. In short, Colstrip makes significant contributions to the State of Montana and is central to the State from an economic and social perspective.

CONCLUSION

63. For the reasons described above, Talen Montana is facing imminent and substantial harm if the MATS Final Rule is not stayed.

Executed on June 27, 2024,

Dale E. Lebsack, Jr.
President of Talen Montana, LLC
Chief Fossil Officer for
Talen Energy Corporation

Attachment A

to

Declaration of Dale E. Lebsack, Jr., President of Talen Montana, LLC and Chief Fossil Officer for Talen Energy Corporation

Select excerpts of Burns & McDonnell Study

CONFIDENTIAL

Colstrip Particulate Matter Control Cost Evaluation – Final

prepared for

Talen Montana
Colstrip, Montana

April 2024

Project No. 163860

prepared by

Burns & McDonnell

TABLE OF CONTENTS

* * * * *

1.0 EXECUTIVE SUMMARY

Burns & McDonnell has been retained to assess the cost of two particulate control options located between the reheat system and the stack to meet the proposed Mercury and Air Toxics Standards (MATS) Rule. The current system is compliant with the existing filter particulate limit of 0.030 lb/MMBtu. The proposed MATS rule would reduce this emission rate to between 0.006 and 0.010 lb/MMBtu. These rates cannot be achieved with the existing control technology or with modifications to the existing control technology. The primary objective of this evaluation is to provide an Association for the Advancement of Cost Engineering (AACE) Class 4 capital cost estimate, and an Operations and Maintenance (O&M) estimate incorporating site specific factors such as considering the power source for the new control system.

Burns & McDonnell evaluated the application of an Electrostatic Precipitator (ESP), or a fabric filter installed after the reheat system but prior to the stack. These options and placement in the flue gas path were selected in the previous Burns & McDonnell evaluation comparing various control technologies and installation locations. The previous study was an AACE Class 5 estimate that is primarily used for comparing relative options. This evaluation has included Colstrip site specific factors to help separate the two leading control options.

1.1 CAPITAL COST ANALYSIS

Burns & McDonnell requested vendor budgetary cost estimates for the ESP and fabric filter. Burns & McDonnell also requested a budgetary cost estimate for the ash handling system. The remaining equipment was estimated either using recent pricing from other projects or internal estimating tools. The vendor estimate for the ESP and fabric filter are supply and install estimates. The remaining equipment was estimated using manhours estimated internally and Union labor rates from RS Means for Montana.

Using this information capital, and O&M costs were then developed for both control technologies. The Total Project Cost is based on the assumption the project will be executed on a multiple contract, lump sum construction bid approach. The total costs do not include Owner's costs such as taxes, allowance for funds during construction, fees, permitting and Owner's contingency. Table 1-1 provides a summary of the two unit total capital costs.

Table 1-1: Summary of Capital Costs for Units 3&4

CAPITAL COST ESTIMATE TALEN MONTANA COLSTRIP POWER STATION FABRIC FILTER AND ESP COLSTRIP, MT BMcD #163860		
Area / Discipline	**REHEAT FABRIC FILTER**	**REHEAT ESP**
Engineered Equipment	$102,894,000	$86,794,000
Civil, Structural & Architectural	$128,820,000	$260,179,000
Mechanical	$7,270,000	$34,888,000
Electrical & I&C	$9,596,000	$10,542,000
Total Direct Cost	**$248,580,000**	**$392,403,000**
Engineering, Start-up, Commercial	$34,065,000	$54,012,000
Escalation	$14,377,000	$27,520,000
Contingency	$59,404,000	$94,787,000
Construction Management	Not Included	Not Included
EPC Fee	Not Included	Not Included
Total Indirect Cost	**$107,846,000**	**$176,319,000**
Total Project Cost	**$356,426,000**	**$568,722,000**
Owner Cost - General, Taxes & Fees	Not Included	Not Included
Owner Cost - Owner Contingency	Not Included	Not Included
Total Project Cost Incl. Owner Cost	**$356,426,000**	**$568,722,000**

Rev.	Rev. Date
0	04/05/24

BURNS McDONNELL

V 4.0

A percentage of the direct costs are included for Engineering, Start Up and Commercial costs. An overall project contingency, 20% of the direct and indirect costs, is included in the indirect costs. The Escalation is based on the project starting in the fall of 2024 and the second unit coming on line 42 months later. An annual escalation rate of four percent (4%) on engineered equipment, five percent (5%) on materials and four percent (4%) on labor and subcontracts has been included.

1.2 O&M COST ANALYSIS

Table 1-2 provides a summary of the two unit estimated operation and maintenance costs for each option.

Table 1-2: Summary of O&M Costs for Units 3&4

	Fixed Costs	Variable Costs	Total O&M
Reheat ESP	$19,820,000	$1,265,000	$21,085,000
Reheat fabric filter	$12,629,000	$2,157,000	$14,786,000

Table 1-3 provides a summary of all the capital and O&M costs plus the cost per ton of particulate removed. Items such as Owner's costs (performance bond, Owner's contingency, and taxes), permitting, funds during construction, are not included. The cost per ton of particulate removed is based on the annual levelized costs and tons of particulate removed from the average historical Colstrip emission rate. Total tons of material collected will likely exceed this amount as it is anticipated the particulate exiting the scrubbers will increase when the pressure drop across the scrubber is decreased to allow for the new control device.

Table 1-3: Particulate Control Cost Summary

Summary of Particulate Emissions Control Costs from Colstrip Units 3&4										
PM-10 Control Alternative (Ranked by PM-10 Rate)	**PM Removal Efficiency %**	**Emissions**				**Economic Impacts**			
		Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost $1,000	Annual O & M Cost $1,000	Total Annual Cost $1000/yr	Average Control Cost $/ton
Reheat ESP	71.45	0.006	95	355	890	568,722	21,085	88,546	99,536
Reheat fabric filter	71.45	0.006	95	355	890	356,426	14,786	57,065	64,148
2022 Baseline (Scrubber)		0.0220	334	1245		N/A	N/A	N/A	N/A

Based on this evaluation the recommended MATS compliance approach for Colstrip Units 3 and 4 is the installation of fabric filters between the flue gas reheat system and the stack. The AACE Class 4 capital cost estimate for both units is a total of $356,426,000 (not including Owner's costs). The levelized annual operation and maintenance of the fabric filter option is $14,786,000 including the addition of a one full time equivalent staff member and 5-year bag replacement cycles. It is anticipated this project will take 36-42 months to complete depending on available outage windows. The anticipated tie in outages are 10 to 12 weeks for Unit 3 and 4 to 6 weeks for Unit 4.

* * * * *

2.0 INTRODUCTION

2.1 COLSTRIP STEAM ELECTRIC STATION

Talen Montana's operates the Colstrip Steam Electric Station in Colstrip, Montana. Units 3 and 4 are each 805 MW coal-fired steam electric generating units and were placed into service in 1984 and 1986, respectively. The units fire a low-sulfur PRB coal. The Colstrip units have particulate scrubbers installed for control of particulates and SO_2. Units 3 and 4 achieve a particulate matter emission rate of approximately 0.022 lb/mmBtu.

The EPA proposed updates to the MATS rule in May 2023. The current rule allows filterable particulate matter (fPM) emission rates of 0.030 lb/MMBtu as a surrogate for acceptable total non-mercury metal hazardous air pollutants (HAPS) emissions. The proposed MATS rule update could reduce this emission rate to as low as 0.006 lb/MMBtu.

A Phase 1 evaluation of several options to reduce fPM emissions at the facility to achieve compliance with the proposed updated MATS identified two compliance options for further evaluation. These options are installing an ESP or fabric filter downstream of the scrubbers and flue gas reheaters. This report presents the results of this further investigation including an AACE Class 4 cost estimate using budgetary quotations from major equipment suppliers. During the Phase 1 evaluation it was noted it is likely an electrical upgrade will be necessary as the plant cannot support the demand for a new ESP. This cost estimate has accounted specifically for this matter as well as other Colstrip specific factors.

2.2 COST DEVELOPMENT

Historically, a Class 4 study would utilize past project information and adapt that information to better fit the unique conditions at a specific site. However, over the last ten years the utility air pollution control market has seen a significant slowdown making past project data either limited or less relevant. To improve the accuracy of the cost estimate Burns & McDonnell contacted vendors that have remained active in the ash conveying and particulate control market either with utilities or at a scale akin to utilities. Southern Environmental Inc, and Industrial Accessories Company are the two companies Burns & McDonnell requested provide budgetary cost estimates for fabric filter. Southern Environmental Inc was also requested to provide a budgetary cost estimate for an ESP. UCC Environmental was contacted for budgetary pricing for the ash handling system.

The cost estimate addressed other equipment such as transformers, control cabinets, silos utilized cost information from more recent projects with these types of equipment. Commodity items such as steel, ductwork, foundations, earth work, etc. were included through quantities developed by Burns & McDonnell or cost factors based on Burns & McDonnell's experience on these types of projects.

2.3 LIMITATIONS AND QUALIFICATIONS

Estimates and projections prepared by Burns & McDonnell relating to schedules, performance, construction costs, and operating and maintenance costs are based on our experience, qualifications, and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

* * * * *

3.0 EMISSION REDUCTION TECHNOLOGY DESCRIPTION

The two technologies evaluated further are the fabric filter (baghouse) and the electrostatic precipitator. This section describes these two control technologies that can be retrofitted to Colstrip to comply with the proposed MATS particulate emissions regulations. Both of fPM reduction technologies that are commercially available. However, neither of these technologies have previously been located at a utility in reheated flue gas downstream of a wet particulate scrubber.

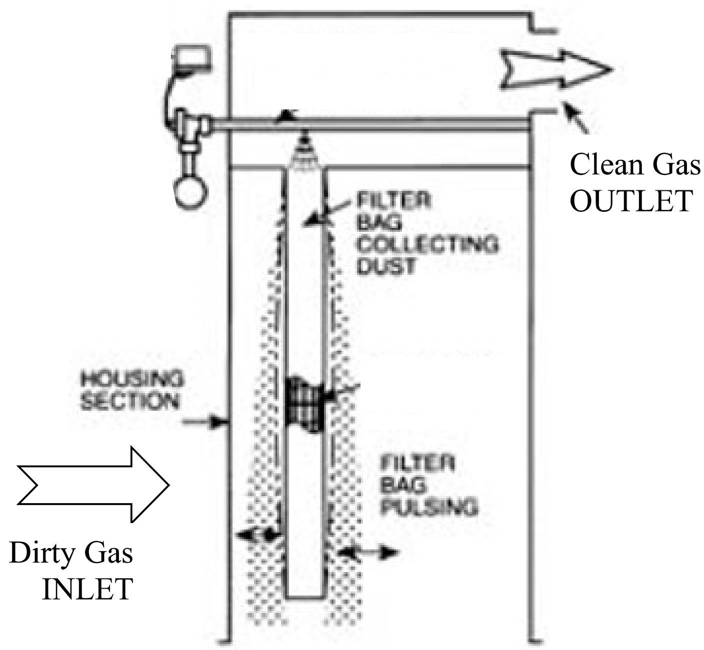
3.1 PULSE-JET FABRIC FILTER

A pulse-jet fabric filter is an effective particulate matter control technology that uses a fabric material to filter out particulate matter from flue gas. The use of filters to remove unwanted items from a system has been around for many centuries. Within the last century, fabric filters have been popular options for particulate control in coal-fired power plants. The process is simple, which is one reason why they are so common. There are multiple types of fabric filters, based on the cleaning method. The method discussed in this section is based on pulse-jet cleaning.

3.1.1 Process Description

A process flow diagram of a typical pulse-jet fabric filter system is provided in Figure 3-1

Figure 3-1: Typical Pulse-Jet Fabric Filter Process Flow Diagram



Pulse-jet fabric filters use the simple process of forcing the flue gas, which contains small particles, through a felted fabric. This process causes the particles to collect on the fabric, usually bags, by sieving. The material of the filter bags is determined by the operating conditions, namely the temperature of the flue gas. Also, the size of the filter bags is dependent upon the gas flow based on an air-to-cloth ratio, to avoid too great of a pressure drop from dust cake buildup.

As the dust cake buildup develops on the filter bags, they require cleaning. For pulse-jet fabric filters, the flue gas flows from outside the felted bags to the inside of the bags, and then the clean gas exhausts at the top of the bags. Therefore, the particles are collected on the outside of the bags. A wire cage is inserted inside the bags to prevent the bags from collapsing during normal operation. The bags are cleaned intermittently by pulse-jet cleaning, which is a short burst of high-pressure air directed at the top of the bag, which establishes a shock wave that proceeds down the bag. The wave-like vibration of the bag causes the particulate buildup on the outside of the bag to fall off the bags and into hoppers. As bags are periodically cleaned, the remaining bags take on the extra demand so that the system can continue to operate while bags are being cleaned. This also maintains a generally constant pressure drop across the system. After passing through the filter bags, the flue gas leaves the fabric filter free of almost all particulate matter.

3.1.2 Pulse-Jet Fabric Filter Advantages

Pulse-jet fabric filters have many advantages in comparison to other particulate matter control technologies:

- Brief cleaning pulse: The flow of flue gas through the bag does not have to be stopped during cleaning because the cleaning pulse is very brief, 0.03 to 0.1 seconds in duration.
- Constant pressure-drop: As some of the bags are being cleaned in the system the remaining bags take on the extra demand. This, along with greater frequency of pulse-jet cleaning, results in a nearly constant pressure drop across the system during operation.
- No isolation needed: Unlike other fabric filters, they do not need extra compartments to maintain necessary filtration because this method does not require isolated compartments of bags.
- Allows for higher gas flow rates and higher dust loadings: Since the pulse-jet cleaning is a very intense and frequent method, these fabric filters can treat higher gas flow rates and higher dust loadings than other fabric filters.
- Allows for smaller fabric filters: Since the pulse-jet cleaning method allows for higher gas flow rates and higher dust loadings, combined with dust cake buildup not being needed for efficient removal – the fabric filters can be smaller than other types of fabric filters in the treatment of the same amount of dust and gas, making higher air-to-cloth ratios possible.
- Uninhibited by gas stream fluctuations: These fabric filters are relatively insensitive to fluctuations in the flue gas stream conditions, so that efficiency and pressure drop are relatively unaffected by these fluctuations.
- Simple operation: Process is based on simple filtration, allowing for a simple operation.
- Simple maintenance: They do not require the use of high voltage, like ESPs do, which allows for simpler maintenance activities.
- Low and high resistivity collection: Fabric filters are effective at collecting particulate matter with either low or high resistivity, while ESPs have a difficult time collecting high resistivity ash.
- Flexible installation: There are many options for fabric filter configurations, allowing it to work for almost any plant set-up.

3.1.3 Pulse-Jet Fabric Filter Disadvantages

There are also various disadvantages to implementing pulse-jet fabric filters as the particulate matter removal technology:

- Ineffective for acid gas removal: Since the operation of fabric filters is based on filtration of solids, they are not effective at removing acid gases because the acid gases and some particulate matter are too small.
- Limited operation temperatures: If the temperature exceeds 550°F special refractory mineral or metallic fabrics are needed, which are expensive.
- Combustible hazard: If the dust being collected is readily oxidized, then the fabric material can burn.
- Relatively high maintenance: Fabric filters have relatively high maintenance needs because of bag replacement and cleaning method. Pulse jet filter bags require replacement more frequently than reverse gas filter bags.
- Dry environment: They do not operate in moist environments. So, they are limited to dry flue gas environments only. If the flue gas does not have sufficient reheat the bags could become wetted and likely require replacement. The proposed design includes bypass duct/dampers to avoid exposing the bags to flue gas during startup periods.
- Pressure drop: Some pressure drop is required for its functionality, around 8 to 10 in. w.c., which increases the load for the ID fan.
- High gas velocity problems: If the gas velocity is very high, then the dust can be drawn from bag to bag instead of falling into the hoppers, which causes the cake layer on the bags to become too thick. To prevent this, additional compartments are required which increases the capital cost.

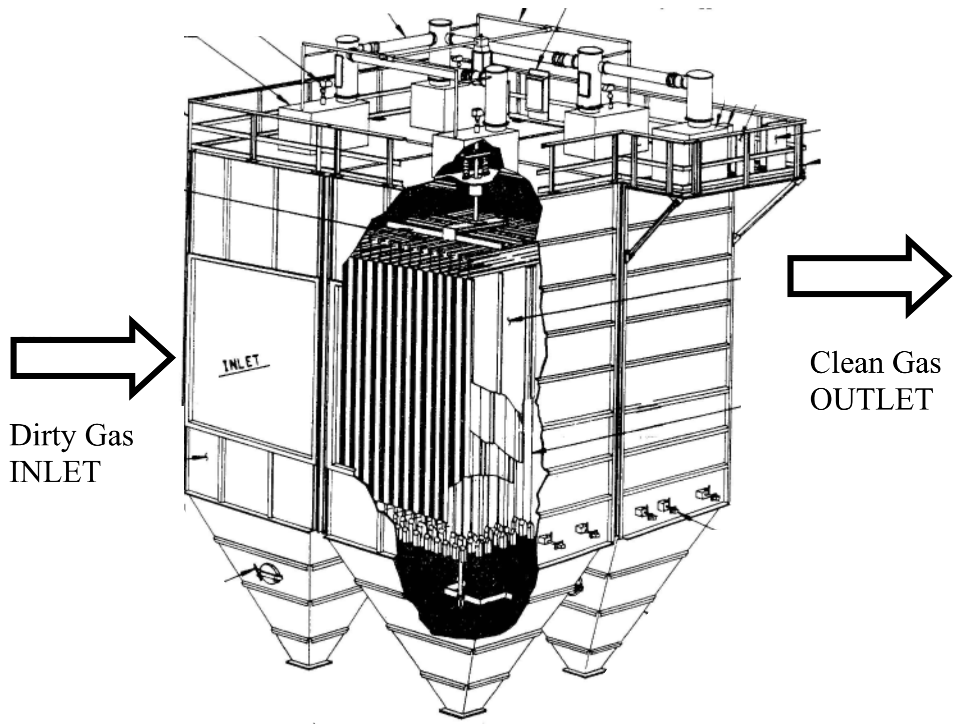
3.2 DRY ELECTROSTATIC PRECIPITATOR

An ESP is an effective particulate matter control technology that uses high voltage electric fields to collect particulate matter from flue gas. This technology is a well proven technology with decades of experience in utility applications. However, the nature of the particulate matter to be collected, specifically the electrical resistivity, can impair the operation of the ESP and the application of a dry ESP downstream of a scrubber on a coal fired boiler is unusual which could introduce unforeseen challenges.

3.2.1 Process Description

A process flow diagram of a typical ESP system is provided in Figure 3-3.

Figure 3-3: Typical Dry Electrostatic Precipitator Process Flow Diagram



ESPs offer an advantage of operating at a very low pressure drop across the system. The ESP is essentially a large box that slows the gas stream and uses an electrostatic attraction to collect the particulate. The ESP is arranged in a series of ‘fields’ which consist of negatively charged discharge electrodes and positively charged collection plates hanging in the gas stream. The discharge electrodes impart a negative charge to the particles in the gas stream. The negatively charged particles are then attracted to large positively charged plates. The particulate is collected on the plates and is periodically removed by “rapping” the plate. Most, but not all of the ash knocked off the plates will fall into the hoppers and will be removed by the ash handling system. Most of the particulate that is re-entrained in the gas stream during rapping is collected in subsequent sections of the ESP. Factors affecting the efficiency of the ESP include flue gas flow rate, resistivity of the ash, plate area, voltage and the number of fields.

ESPs are typically constructed of carbon steel and thus do not have significant corrosion resistance. In addition, the collection mechanism of the dry ESP requires dry particulate matter. If the collected materials were wet, the moisture would diffuse the induced charge and reduce the collection efficiency of the ESP. Also, wet materials would be difficult to dislodge from the collection plates, which would also reduce collection efficiency. Therefore, dry ESPs are primarily filterable particulate collection systems intentionally operated under conditions that minimize condensation and collection of the resulting condensable particulate matter. Vendors indicate that guarantees for filterable emissions limits from an ESP are comparable to fabric filters.

3.2.2 Electrostatic Precipitator Advantages

An ESP is an efficient particulate matter removal device and has many advantages compared to other particulate matter control devices:

- Low pressure drop: An ESP only minimally hinders flue gas flow because of the lack of large obstructions in the flue gas resulting in a small pressure drop across the system.
- High removal efficiency: In a typical application they are capable of very high removal efficiencies of particulate matter removing between 99 and 99.9%.

3.2.3 Electrostatic Precipitator Disadvantages

There are also various disadvantages to an ESP compared to other particulate matter removal technologies:

- Very sensitive to gas flow: They are very sensitive to changes in flue gas stream conditions, so they are usually not suited for highly variable processes.
- Installation limitations: They are generally very large in order to obtain low gas velocities necessary for efficient removal, which causes problems when there is limited space for installation.
- Sophisticated maintenance requirement: They require relatively sophisticated maintenance personnel to operate and maintain because of the high voltages.
- Ozone production: During gas ionization, the negatively charged electrodes produce ozone.

* * * * *

4.0 EMISSION GUARANTEES

The typical location for either a dry ESP or fabric filter is immediately downstream of an air heater. This location is typical primarily due to the flue gas temperature in this location. The temperature after the air heater is much cooler than upstream but is still above the flue gas acid dew point (and well above the moisture dew point) during normal operation. The cooler temperature reduces the volume of the flue gas and thus the size/cost of the ESP and fabric filter but the temperature remains high enough to prevent liquid from condensing therefore protecting the ESP or fabric filter from liquid that could impact performance or reliability.

The application at the Colstrip facility is different from this typical configuration. The Colstrip units have a wet particulate scrubber that cools and saturates the flue gas while removing both particulate and sulfur dioxide. The existing system also includes a reheat system that warms the exiting flue gas and is designed to result in a dry flue gas. The proposed location for the new ESP or fabric filter is downstream of this reheat system and not in the typical location immediately downstream of the air heater. This location was selected in the previous study by Burns & McDonnell as the proposed location is a more cost-effective option. Due to the atypical nature of this design Burns & McDonnell made it a point to discuss this with the vendors to gain confidence the vendors would guarantee performance in this configuration.

In discussion with Southern Environmental Inc, they indicated that using either technology they are confident that both of the proposed MATS rates (0.010 or 0.006 lb/MMBtu) could be achieved, maintained, and guaranteed at the Colstrip facility. Preliminary discussions (not final) with Industrial Accessories Company indicated they are hesitant to commit to providing guarantees at Colstrip due to the fabric filter unusual application (gas path location).

Southern Environmental Inc is a long-term supplier of both ESP and fabric filter systems and has remained active in the large-scale market for these systems. Burns & McDonnell emphasized the importance of accurately stating if guarantees would be offered keeping in mind similar make right terms the Utility industry has historically required. Southern Environmental Inc acknowledged the point Burns & McDonnell was making and indicated they had considered that when stating the rates could be guaranteed.

* * * * *

5.0 COST EVALUATION

Included in this section of the report are the cost estimates for both control technologies evaluated for application at Colstrip. Both the capital cost and the O&M costs were estimated using vendor supplied budgetary cost estimates for the reheat fabric filter, reheat ESP, and ash handing systems. Burns & McDonnell in-house estimating software and tools were used to determine the supply and installation costs that were not otherwise supplied by vendors. Appendix B contains details from all the vendor quotations received.

5.1 CAPITAL COSTS

The Total Direct Costs (TDC) from Table 5-1 includes the capital costs plus balance of plant mechanical and electrical costs (i.e., ductwork, insulation, electrical upgrades, piping, etc.) and the cost for materials and labor required for installation. Total Project Cost in Table 5-1 includes the total direct costs plus indirect costs such as engineering, escalation, contingency, and other miscellaneous indirect costs. The Total Project Cost is based on the assumption the project will be executed on a multiple contract, lump sum construction bid approach. These costs do not include Owner's costs such as taxes, allowance for funds during construction, fees, permitting and Owner's contingency.

Additional details regarding what is included by the primary disciplines are outlined later in this section.

Table 5-1: Capital Cost Summary for Units 3&4

CAPITAL COST ESTIMATE
TALEN MONTANA
COLSTRIP POWER STATION
FABRIC FILTER AND ESP
COLSTRIP, MT
BMcD #163860

Area / Discipline	REHEAT FABRIC FILTER	REHEAT ESP
Engineered Equipment	$102,894,000	$86,794,000
Civil, Structural & Architectural	$128,820,000	$260,179,000
Mechanical	$7,270,000	$34,888,000
Electrical & I&C	$9,596,000	$10,542,000
Total Direct Cost	**$248,580,000**	**$392,403,000**
Engineering, Start-up, Commercial	$34,065,000	$54,012,000
Escalation	$14,377,000	$27,520,000
Contingency	$59,404,000	$94,787,000
Construction Management	Not Included	Not Included
EPC Fee	Not Included	Not Included
Total Indirect Cost	**$107,846,000**	**$176,319,000**
Total Project Cost	**$356,426,000**	**$568,722,000**
Owner Cost - General, Taxes & Fees	Not Included	Not Included
Owner Cost - Owner Contingency	Not Included	Not Included
Total Project Cost Incl. Owner Cost	**$356,426,000**	**$568,722,000**

Rev.	Rev. Date
0	04/05/24

BURNS McDONNELL

V 4.0

5.1.1 General Estimate Basis

A summary of the project cost estimate is included herein. The Project Cost Estimate is based on the site general arrangement (Appendix A) and multiple contract approach. Pricing for major equipment was obtained from equipment supplier budgetary quotes specific to this project. This includes equipment such as the ESP and fabric filter. Major electrical equipment was estimated using recent project costs for similar equipment. Minor equipment was estimated using recent project costs or in-house estimating methods. The majority of the materials have been estimated using current costs obtained from an in-house database or from recent, similar projects.

Union labor rates from RS Means for Montana were used to estimate the labor rate. The basis for the development of direct field hours is an in-house database, applying a working conditions factor unique to the Colstrip facility. The project is estimated assuming a 50-hour, 5 day work week during construction.

5.1.1.1 Indirect Costs

A percentage of the direct costs are included for Engineering, Start Up, and Commercial costs. An overall project contingency, 20% of the direct and indirect costs, is included in the indirect costs. The Escalation is based on the project starting in the fall of 2024 and the second unit coming on line 42 months later. An annual escalation rate of four percent (4%) on engineered equipment, five percent (5%) on materials and four percent (4%) on labor and subcontracts has been included.

5.1.1.2 Items Excluded from Estimated Costs

No Burns & McDonnell Construction Management has been included in the estimated costs. No construction facilities, parking, laydown, turnstiles, etc., have been included in the estimated costs. No Interest During Construction costs or financing fees are included in the estimate. No costs have been included for hazardous material remediation.

5.1.2 Discipline Information

The following are brief outlines of the information and scope of each discipline considered in developing the equipment cost estimate and quantities.

5.1.2.1 Electrical

For the ESP it was assumed the existing auxiliary electric system could not support the new electrical loading of the added ESP electrical loads. The ESP auxiliary electric systems are derived from the 115kV system east of the Unit 4 scrubber building with a new auxiliary transformer tapped from the existing

115kV line. A new relay panel for 115kV line and transformer protection in the existing unit 4 scrubber building was accounted for in the estimate basis. A new 4.16kV ESP switchgear was accounted for in the unit 4 ESP power distribution centers (PDC) to distribute power to 4.16kV/480V station service transformers for the unit 3 and 4 ESP units. Each unit then has local 480V switchgear, motor control centers (MCCs), panelboards, and local uninterruptable power supply (UPS)/direct current (DC) as required to support the ESP unit electrical loads.

For the fabric filter it was assumed the existing 3 and 4 scrubber auxiliary electric system has electrical loading capacity to support the new fabric filter electrical loading. New power feeds were accounted for from the scrubber units power distribution centers (PDC) to distribute power to 4.16kV/480V station service transformers for the unit 3 and 4 fabric filter units. It was assumed the existing scrubber 4.16kV switchgears had spare breakers that would need to be replaced or retrofitted due to relaying and arc flash requirements. For the new air compressors low voltage variable frequency drives (VFDs) would be required provided by the compressor vendor for motor starting. Each fabric filter unit PDC then has local 480V MCCs, panelboards, and local UPS/DC as required to support the fabric filter unit electrical loads.

For both fabric filter and ESP options the following estimate basis was used. That construction power would be available from the existing auxiliary power system. A local ground grid would be created for the ESP and fabric filter that would tie into the plant's existing ground grid. A spare 4.16kV/480V station service transformer was included. Unit 3 and 4 electrical systems were electrically separated at the 480V level and below. It was the plant has existing paging system, telecom, fire protection alarm systems that would be extended to the area. For estimating purposes the ESP or fabric filter vendor supplied all the wiring, raceway, lighting local from the ESP/fabric filter back to the PDCs.

5.1.2.2 Controls

For the ESP option, included in this rough estimate are the management, engineering, equipment, shipping, and field support costs to commission remote input / output (IO) cabinets into the existing distributed control system (DCS). This estimate assumes that existing DCS vendor on record is GE. This estimate includes the engineering and procurement of quantity four remote IO cabinets to be brought back into the existing DCS system. The four remote IO cabinets will contain a total of 845 system hardwired points (20% spares included) and datalink interface to supervisory system. Included in this estimate are spares and startup replacements that the field support may require while commissioning the system. estimate includes time for field support to power check, establish communication to existing system, and startup.

For the fabric filter option, included in this rough estimate are the management, engineering, equipment, shipping, and field support costs to commission remote IO cabinets into the existing DCS. This estimate assumes that existing DCS vendor on record is GE. This estimate includes the engineering and procurement of quantity four remote IO cabinets to be brought back into the existing DCS system. The four remote IO cabinets will contain a total of 825 system hardwired points (20% spares included). Included in this estimate are spares and startup replacements that the field support may require while commissioning the system. The estimate includes time for field support to power check, establish communication to existing system, and startup.

5.1.2.3 Structural

The conceptual design, layout, and material quantities for the ESP structure are developed per the plan and elevation views of the component provided within the vendor (SEI-Group) quote. The proposed structural layout plan and elevation views for the ESP structure are shown in drawings SKS003 and SKS004 respectively. The ESPs are located in the available space towards the South of the units. It is assumed that inlet branch lines are added to the existing flue duct at the elbows upstream of the stack for each unit at the existing elevations. The outlet from the ESP's would branch into the existing flue gas ducts just upstream of the reducers and prior to the main lines entering the stack.

The structural estimate includes the material quantities for the gas flue ductwork, duct support steel, ESP building steel, foundation concrete, and concrete reinforcement. The ESP building steel quantities are developed based on information regarding steel densities for a similar size plant. The ductwork quantities are developed based on the lengths calculated in the conceptual layout and the perimeter for the assumed duct cross section. The calculated surface area is then multiplied by an estimated weight per square footage value which is a proprietary metric developed based on experiential data from multiple past projects to develop the total tonnage of gas flue duct steel. The ductwork is assumed to be supported by support steel frames that are approximately 75' in height. The total length of the ductwork is multiplied by an estimated weight per cubic foot value which is a proprietary metric developed based on experiential data from multiple past projects to develop the total tonnage of support steel below the ductwork.
The foundation is assumed to be constructed using reinforced concrete spread footings on piles. The ESP building foundation is assumed to consist of spread footings on piles. Each spread footing consists of a pedestal and pile cap with five (5) piles per footing. The piles are estimated to be of 18" diameter concrete extending approximately 60' below grade. The foundation for the duct supports is estimated to be a 5'

pile cap supported by fifteen (15) concrete piles per support frame. The concrete piles for duct support steel are also estimated to be of 18" diameter concrete extending approximately 60' below grade.

The conceptual design, layout, and material quantities for the fabric filter are developed per the plan and elevation views of the component provided within the vendor (SEI-Group) quote. The proposed structural layout plan and elevation views for the fabric filter structure are shown in drawings SKS001 and SKS002 respectively. The fabric filter buildings are located in the available space towards the South of the units. It is assumed that inlet branch lines are added to the existing flue duct at the elbows upstream of the stack for each unit at the existing elevations. The outlet from the fabric filter structures would branch into the existing flue gas ducts just upstream of the reducers and prior to the main lines entering the stack.

The structural estimate includes the material quantities for the gas flue ductwork, duct support steel, steel, foundation concrete, and concrete reinforcement. The fabric filter building steel quantities are included in the vendor cost estimate and hence not included here. The ductwork quantities are developed based on the lengths calculated in the conceptual layout and the perimeter for the assumed duct cross section. The calculated surface area is then multiplied by an estimated weight per square footage value which is a proprietary metric developed based on experiential data from multiple past projects to develop the total tonnage of gas flue duct steel. The ductwork is assumed to be supported by support steel frames that are approximately 126' in height. The total length of the ductwork is multiplied by an estimated weight per cubic foot value which is a proprietary metric developed based on experiential data from multiple past projects to develop the total tonnage of support steel below the ductwork.

The foundation is assumed to be constructed using reinforced concrete spread footings on piles. The fabric filter building foundation is assumed to consist of spread footings on piles. Each spread footing consists of a pedestal and pile cap with five (5) piles per footing. The piles are estimated to be of 18" diameter concrete extending approximately 60' below grade. The foundation for the duct supports is estimated to be a 5' pile cap supported by fifteen (15) concrete piles per support frame. The concrete piles for duct support steel are also estimated to be of 18" diameter concrete extending approximately 60' below grade.

5.1.2.4 Mechanical

Both the ESP and fabric filter options include 2x100% air compressors per unit and a single receiver per unit. The size of the air compressors are much larger in the fabric filter option. Air piping has been included to connect to all air users, and provide air connections around the perimeter of the top of the new equipment and between the rows of hoppers under the new equipment.

The ash handing system is a negative pressure conveying arrangement designed such that the ash from the hoppers will be conveyed in a single conveying line to a new common ash silo. At the ash silo there will be a single filter/separator on top of the silo with an 18" double gate valve. The filter separator will be operated intermittently and will be equipped with a vacuum breaker. Mechanical exhausters (2x100%), with automatic crossover valves, are included.

5.2 OPERATION AND MAINTENANCE, LEVELIZED COSTS

The O&M cost estimates for the various control technology options evaluated for Colstrip included in this study are summarized in Table 5-2.

Table 5-2: O&M Cost and Levelized Cost Summary

Summary of Particulate Emissions Control Costs from Colstrip for Units 3&4									
PM-10 Control Alternative (Ranked by PM-10 Rate)	PM Removal Efficiency %	Emissions				Economic Impacts			
		Emission Rate lb/MMBtu	Hourly Emission Lbs/Hr	Annual Emission Tons/yr	Emission Reduction Tons/yr	Installed Capital Cost $1,000	Annual O & M Cost $1,000	Total Annual Cost $1000/yr	Average Control Cost $/ton
Reheat ESP	71.45	0.006	95	355	890	568,722	21,085	88,546	99,536
Reheat fabric filter	71.45	0.006	95	355	890	356,426	14,786	57,065	64,148
2022 Baseline (Scrubber)		0.0220	334	1245		N/A	N/A	N/A	N/A

5.2.1 O&M Cost Basis

O&M costs for the evaluated systems at Colstrip assuming the following parameters:

- Power cost of $45/MWh.
- Operating labor rate of $200,000 for one full time equivalent (FTE).
- Cost of Money 8.25%
- Levelization period, 15 years
- Waste disposal cost, $15/ton
- Unit 3 and 4 capacity factor of 85.0%
- Bag replacement every 5 years for the fabric filter.
- 5% of direct cost for average annual equipment maintenance

* * * * *

6.0 SUMMARY

6.1 SUMMARY

Burns & McDonnell has been retained to assess the cost of two particulate control options located between the reheat system and the stack to meet the proposed MATS Rule. The main objective of this evaluation is to provide an AACE Class 4 cost estimate incorporating site specific factors such as considering the power source for the new control system.

In Section 3, the two control technologies were described. In Part 4, the availability of Colstrip to have guarantees for the technologies was discussed. In Part 5, capital and O&M costs for the two options were estimated.

6.1.1 Balance of Plant Impact Analysis

The compliance plan selected will impact balance of plant equipment at Colstrip. Further detailed studies will be necessary to fully define the detailed scope of the project.

- An ash disposal study should be performed to determine the best method of ash disposal and placement of the ash handling equipment.
- A balance of plant utility interface study should be performed to determine the most cost effective approach on plant utilities such as instrument air, service air, etc.
- A draft system study should be conducted prior to execution of any retrofit technologies. This study would identify any ductwork that would need stiffening or replacement due to the changed pressure drop profile through the system.
- An electrical load study should be conducted to address the addition of the new air pollution control equipment to Colstrip that increases the power consumption at the plant. This study would confirm if the existing station transformers have the capacity to support the balance of plant (BOP) power needs and air compressors. It could also identify potential other, more cost effective, sources of power. For purposes of this study, it was assumed the ESP would be powered by a new transformer connected to the grid. The other systems would be powered from the existing MCC's in the scrubber building.

* * * * *

Attachment B

to

Declaration of Dale E. Lebsack, Jr., President of Talen Montana, LLC
and Chief Fossil Officer for Talen Energy Corporation

Declaration of Dale E. Lebsack, Jr. in support of staying the GHG Rule

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

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No.: 24-1128

DECLARATION OF DALE E. LEBSACK, JR.

I, Dale E. Lebsack, Jr., declare as follows:

1. I currently work as Chief Fossil Officer for Talen Energy Corporation ("Talen"). 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. Petitioners Talen Generation, LLC and Talen Montana Holdings, LLC (the "Talen Entities") are wholly owned subsidiaries of Talen. Talen is an independent power producer that owns and operates approximately 10.7 gigawatts of power infrastructure in the United States. Talen produces and sells electricity, capacity, and ancillary services

into wholesale U.S. power markets, including PJM Interconnection, LLC ("PJM") and the Western Electricity Coordinating Council ("WECC"), with Talen's generation fleet principally located in the Mid-Atlantic and Montana. Talen's generation fleet includes wholly owned and partially owned assets that use nuclear, coal, oil, and natural gas as fuels.

3. In my current position as Chief Fossil Officer at Talen, I am responsible for asset management and operations for Talen's fossil generating assets in PJM, WECC, and ISO New England. In that capacity, I also serve as President of Talen Generation, LLC, which indirectly owns the fossil generating assets in PJM and is an affiliate of Talen. I have worked for Talen and its predecessor companies for over 19 years. Over that time, I have held roles of increasing responsibility in multiple aspects of fossil power generation, including asset management, plant operations, engineering, environmental, health and safety, and project development. I have directly managed merchant generating assets in ERCOT, PJM, ISO-NE, NYISO, WECC, and SERC. The plants that I managed have utilized a wide range of technologies, including coal, gas, oil, and biomass-fired boilers; combined cycle units of varying configurations; and simple cycle gas turbines of differing designs.

4. This declaration is submitted in support of the Petitioner's motion for stay of the U.S. Environmental Protection Agency's final rule entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units;*

and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with the Talen Entities' operations, including generation, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect the Talen Entities.

5. Talen has ownership interests in coal-fired units that are projected to operate at relatively high capacity factors and will be subject to the Final Rule.

6. Talen is the operator of Units 3 and 4 at the Colstrip Steam Electric Station ("Colstrip") in Rosebud County, Montana. Talen also has a 15 percent ownership stake in these units, which currently consist of two active coal-fired generating units capable of producing up to 1,480 MW of electricity that have been operating for approximately 38 years. Each of the units has approximately 740 MW of generating capacity, and the adjacent Rosebud coal mine supplies Colstrip's low-sulfur subbituminous coal. Units 3 and 4 are the only remaining active units at Colstrip, as Units 1 and 2 recently retired in 2020. Units 3 and 4 have a useful life of at least another two decades.

7. Colstrip is one of the largest coal-fired electric generating facilities west of the Mississippi River, supplying electricity throughout Montana and the Pacific Northwest. Colstrip plays an integral role in maintaining operation of the NorthWestern Balancing Authority in Montana, especially during peak electricity demand events.

THE FINAL RULE

8. The Final Rule establishes, under Section 111(d) of the Clean Air Act, best systems of emission reduction ("BSERs") for existing coal-fired steam generating units

that States must use when setting CO_2 emissions limits for such units. 89 Fed. Reg. at 39,840. Under the provisions of the Rule, Colstrip Units 3 and 4 have three options: (1) retire by January 1, 2032; (2) meet an emission rate based on 40% natural gas co-firing by January 1, 2030, and retire by January 1, 2039; and (3) install and operate 90% efficient carbon capture and storage ("CCS") by January 1, 2032, which would allow the unit to operate after 2038. Based on Talen's assessment, the only compliance strategy available for Colstrip consists of shutting down the plant by January 1, 2032.

9. The CCS BSER established by the Final Rule for existing coal-fired steam units is not yet adequately demonstrated, is not achievable, and is not cost-effective. Further, EPA has established deadlines for incorporating this technology, or in the alternative gas co-firing, that are so unreasonable that they likely cannot be met—even if the technologies were adequately demonstrated and achievable. The end result is that owners and operators will have little choice but to retire such units prematurely.

IMPACT OF THE FINAL RULE ON COLSTRIP

10. The Rule requires major modifications to Colstrip Units 3 and 4 or premature retirement of the Units. Specifically, a decision must be made immediately between the three possible compliance choices (retire by 2032, co-fire gas by 2030, or install full CCS by 2032) in order to complete any retrofits in time for the Rule's compliance deadlines. Prematurely shutting down Colstrip would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission.

USCA Case #24-1120 Document #2056093 Filed: 05/24/2024 Page 45 of 428

11. Feasibility and cost evaluations of each compliance option, not to mention financing, engineering, design and construction of the gas-cofiring and CCS options, require years of planning. Additionally, Colstrip is co-owned by six companies, including many utilities subject to PUC regulation in multiple states. The selection of a future compliance option must be agreed upon by a majority of ownership. After the evaluation of compliance options is complete, approval of an option will be difficult and take more time due to the plant's ownership structure.

12. If the CCS and gas co-firing compliance options are impossible or near impossible to meet the Rule's deadlines, or prove prohibitively expensive to undertake, especially in light of future uncertainty, the Rule requires retiring Colstrip Units 3 and 4 by January 1, 2032.

Feasibility and Cost Issues are Compounded by EPA's New MATS Rule

13. Furthermore, the compliance decision for the Rule is intertwined with the EPA's also recently-issued final rule entitled *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 89 Fed. Reg. 38,503 (May 7, 2024) ("MATS Rule").

14. For Colstrip to operate beyond 2027, under the MATS rule, additional costly filterable particulate matter ("fPM") controls must be installed, commissioned, and operable on Units 3 and 4 by July 8, 2027.

15. Colstrip would need to undertake a massive and complex construction project to install, test, and implement these new controls – the costs of which are estimated to exceed $350 million.

16. If the only feasible compliance option for the Final Rule is found to be retirement, then the investment in fPM controls for just over four years (late 2027 to the end of 2032) would be even less justifiable than otherwise. Indeed, a return period of four years on a greater than $350 million investment in fPM controls would be extremely difficult to justify, thus likely requiring Colstrip to shut down by the MATS Rule's compliance deadline of July 2027.

CCS is Not Achievable at Colstrip

17. CCS is impracticable and infeasible at Colstrip. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they can achieve 90% capture of carbon using CCS by 2032. However, this is not possible at Colstrip for the following reasons.

18. The technology to reliably achieve 90% capture of CO_2 using CCS is not adequately demonstrated or readily available. As described above, CCS is an emerging technology that remains unreliable, as well as prohibitively expensive. And there is not enough time to undertake all of the evaluations and studies, design, engineering, and construction of a CCS system at Colstrip. Talen would not invest hundreds of millions of dollars in a technology that is at best uncertain to work and that, in fact, Talen believes will not work as EPA claims it would by the Rule's deadline.

19. Technological issues related to carbon capture are not the only reason Colstrip would be unable to rely on the CCS pathway to comply with the Final Rule. Even if 90% of CO_2 could be captured by 2032, it would need to be transported for storage and stored. Sequestration sites have not been adequately demonstrated in the vicinity of Colstrip and would require additional time, exploration, and significant cost to complete, in addition to the costs associated with transportation of the CO_2. Colstrip, located in eastern Montana, is not near to any developed CO_2 sequestration sites. It is not known whether the geological formations necessary for CO_2 sequestration exist in the vicinity of Colstrip, and additional drilling and exploration would be required to determine this. Further, no pipeline currently exists to carry captured CO_2 from Colstrip to a storage location.

20. In fact, a study referenced in the proposed Rule reports that the costs of transportation and storage for the purposes of CCS are much higher in Montana's Powder River Basin than in other states. CO_2 pipeline transportation and storage cost in 2018 was $22/tonne for the Powder River Basin. The other basins in the study were Illinois ($10/tonne), East Texas ($11/tonne) and Williston ($15/tonne).

21. On top of these prohibitive costs, there are a number of other challenges associated with evaluating, permitting, siting, designing, and constructing such a CO_2 pipeline. Permits and easements would need to be acquired. It is unlikely such a pipeline could be constructed and operational prior to the compliance date required by the Final Rule.

22. The provision allowing for a one-year extension in the compliance deadline where the delay is needed to complete installation of controls and where the company has taken all steps necessary to otherwise meet the deadline does not make a difference. It is equally unrealistic to expect CCS to be constructed and operational at Colstrip by January 1, 2032, as it is unrealistic to expect it by January 1, 2033.

23. For the reasons outlined above, CCS is not an option for Colstrip.

Gas Co-Firing is Not Achievable at Colstrip

24. As an alternative to CCS, the Final Rule allows affected coal-fired EGUs to remain in operation until January 1, 2039, if they begin co-firing with 40% gas by 2030.

25. A project to retrofit Colstrip to co-fire gas would be exceedingly complicated and expensive. According to preliminary evaluations, conversion of Units 3 and 4 to allow for co-firing of gas would cost in excess of $150 million.

26. In addition to the retrofitting, co-firing gas at Colstrip would require new infrastructure that does not exist. The closest gas transmission pipeline is over 100 miles away. Building such a pipeline would cost on the order of $200 million or more and is economically infeasible. In addition, there are a multitude of challenges and high-cost items, especially involving the need for easement acquisition and permitting for a pipeline estimated to be over 100 miles long.

27. Putting aside that gas co-firing at Colstrip is so costly that it is economically infeasible (*i.e.*, such a costly project would make the Colstrip plant financially unviable), it is also technically near impossible to execute by 2030. A 100-mile gas pipeline is a massive construction project that requires a long lead time for design,

USCA Case #24-1120 Document #2056249 Filed: 05/22/2024 Page 45 of 958

permitting, siting, procurement, and construction. It is also the type of project that will engender protracted challenges. It is highly improbable such a project can be accomplished by the Final Rule's deadline.

28. The provision allowing for a one-year extension in the compliance deadline where the delay is needed to compete installation of controls and where the company has taken all steps necessary to otherwise meet the deadline does not make a difference. It is equally unrealistic to expect a 100-mile gas pipeline to be constructed for Colstrip by January 1, 2030, as it is unrealistic to expect it by January 1, 2031.

29. For the reasons outlined above, gas-co-firing is not an option for Colstrip.

Without a Stay, Talen will Suffer Immediate, Irreparable Harm

30. During the pendency of this litigation, the Talen Entities would sustain the following concrete, irreparable harms if a stay of the Final Rule is not granted:

a. The costs to immediately begin designing, constructing, and permitting a gas pipeline for the ability to co-fire gas at Colstrip and to retrofit the units to provide for co-firing with gas; or

b. The costs to retrofit Colstrip with CCS, to begin construction of a pipeline to transport CO_2 for sequestration, and to evaluate and develop an acceptable site for sequestration.

31. Talen personnel would immediately begin to dedicate substantial time, attention, and resources to tasks associated with evaluating, designing, and financing such projects, which would divert attention from other important duties.

32. Dollars spent on design, permitting, engineering, and other studies cannot be refunded once they are spent. The costs associated with implementing 40 percent natural gas co-firing or installing CCS to achieve 90 percent capture of CO_2 so that Colstrip can operate beyond 2032 are massive. Colstrip would need to spend significant time, resources, and investments to not only implement the technologies, but also to construct supporting infrastructure. When added to the costs associated with complying with the proposed requirements in other rulemakings that impact Colstrip, such as the 2024 MATS Rule, the investments required for Colstrip to operate beyond 2032 would cost many hundreds of millions of dollars. Such costs would likely render Colstrip financially unviable, given Colstrip's uncertain but limited future.

Premature Retirement is the Only Option for Colstrip

33. Given that the CCS and co-firing compliance options are nearly impossible to execute successfully by the Rule's deadlines, and given that the costs of these compliance options would be prohibitively expensive to undertake, especially in light of future uncertainty, the Rule requires retiring Colstrip Units 3 and 4 by January 1, 2032. As discussed above, moreover, the interplay between the Rule and the MATS Rule means that Colstrip would likely retire by July 2027.

34. This litigation is likely to take a minimum of 2 to 3 years. If the Rule is not stayed, Talen will have suffered irreparable harm by the time the legality of the rule is determined. Before we know whether the rule will be struck down, Talen would have to elect – within a year at the most – to shut down Colstrip, and it would have to actually shut down the plant by mid-2027.

35. A decision to retire Colstrip, especially if forced to be made quickly, will have irreversible impacts to the small community around the plant and the neighboring Rosebud Mine. The mine and the power plant are the only employers of any size within 50 miles and contribute immensely to the local economy and tax revenues.

36. In addition, the Talen Entities would face increased costs related to environmental remediation that is ongoing at Colstrip, pursuant to an Administrative Order on Consent between Talen and the Montana Department of Environmental Quality. The current groundwater remediation system reuses captured water at Units 3 and 4. If the Units are prematurely shut down, additional wastewater treatment systems would be needed, which would increase overall remediation costs by approximately $2.5 million per year during the period of the premature shutdown.

The Public will Suffer Irreparable Harm if Colstrip is Retired Prematurely

37. Further, Colstrip is vital to ensuring that Montanans have affordable and reliable electricity, especially during peak winter and summer months. Colstrip is one of Montana's most important energy assets, especially as demand for reliable baseload power in the western U.S. continues to grow.

38. The likely end result of the Final Rule on Colstrip is that its owners and operators, including the Talen Entities, will have little choice but to retire the units prematurely. Such decisions will change the makeup of the nation's electricity system and increase risks to electric and transmission system reliability.

39. Risks to electricity system reliability, driven in part by the early retirement of dispatchable, high-capacity factor thermal EGUs such as Colstrip, is a matter of

USCA Case #24-1090 Document #2056303 Filed: 05/24/2024 Page 48 of 453

significant concern. WECC reports that current utility resource plans in the western interconnect "are not sufficient to meet future demand over each of the next 10 years," and that "starting in 2026, the number and magnitude of demand-at-risk hours increase by orders of magnitude."[1]

a. In statements made in comments on both the proposed MATS rule and the proposed version of this Rule in 2023, Northwestern Energy indicated that there will not be sufficient replacement power on the grid by 2027 if Colstrip must retire.

40. Colstrip Units 3 and 4 generated approximately 41 percent of the electricity generated in Montana in 2022 and represented 23 percent of total installed generating capacity. A decision to prematurely retire Colstrip, an important baseload generator serving at least five states, would cause significant reliability concerns. These concerns would apply well into the rest of the decade, even if the Rule is not stayed and is struck down by the courts at around the same time the plant would shut down.

Dale E. Lebsack, Jr.

Dated: May 24, 2024

---

[1] Western Electricity Coordinating Council, 2023 Western Assessment of Resource Adequacy (Nov. 2023), *available at* https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf (Attachment A).

Attachment C

to

Declaration of Dale E. Lebsack, Jr., President of Talen Montana, LLC
and Chief Fossil Officer for Talen Energy Corporation

Economic Study by Dr. Patrick M. Barkey, Ph.D.

The Economic Implications of MATS Rulemaking in Montana
Final Report

On April 25, 2024, the U.S. Environmental Protection Agency released a final rule significantly revising the Mercury Air and Toxics Standards (MATS) for coal-fired electric power plants. That rule would require substantial investment at the Colstrip Steam Electric Station (SES), Montana's largest electric generating facility located in Rosebud County in southeast Montana, to continue operation. Such an investment may not be technically or financially feasible for the facility. This would render the continued operation of the Colstrip SES beyond the date of July 8, 2027, when the applicable provisions of the new MATS go into effect, in doubt.

Should the MATS rulemaking result in the premature closure of the Colstrip SES, it would be a significant economic event. This was demonstrated by a 2018 study published by the University of Montana Bureau of Business and Economic Research (Bureau of Business and Economic Research, 2018), which found that an early closure of the coal-fired generator would have sizable impacts on jobs, incomes, tax revenue and population.

A key factor that contributed to the size and scope of the impacts identified in that study is the close relationship of the generating station to the adjacent Rosebud coal mine, owned and operated by Westmoreland. The Colstrip SES is a mine mouth plant, receiving its coal via a dedicated conveyor from the mine. With no rail access to ship its coal to the broader market, any circumstance that terminates electricity generation at the Colstrip SES would bring about the closure of the mine.

The purpose of this report is to bring those estimates of economic impacts up to date, using the most current operating information and conforming to the specific timetable of the MATS rulemaking. The research question addressed is: what would be the consequences for the Montana economy, in terms of jobs, income, spending, output and population, if the new MATS rulemaking brought about the closure of the Colstrip SES in mid-2027?

The basic approach of this research is to compare two futures for the state economy. The baseline projection is a status quo scenario where the generating station and the adjacent mine continue to operate as today. The alternative scenario is premature retirement of the two facilities, with production ceasing in mid-2027. In the alternative scenario, the economic flows ultimately supported by the production of electricity from the Colstrip SES, are removed from the economy, with important implications for those who receive those flow and spend again in the economy.

The difference between these two projections of the future of the Montana economy is the economic impact of the Colstrip SES closure. We produce these projections with an economic model that has been constructed and calibrated for this purpose, leased from Regional Economic Models, Inc. (REMI). The REMI model, described in more detail in Appendix B of this report, has been extensively documented and utilized in both peer-reviewed and other research studies. The model combines a detailed, 70-sector economic output model, a multi-equation econometric model and a demographic model to serve as a powerful tool to assess policies and events affecting the economy (Cassing & Giaratini, 1992).

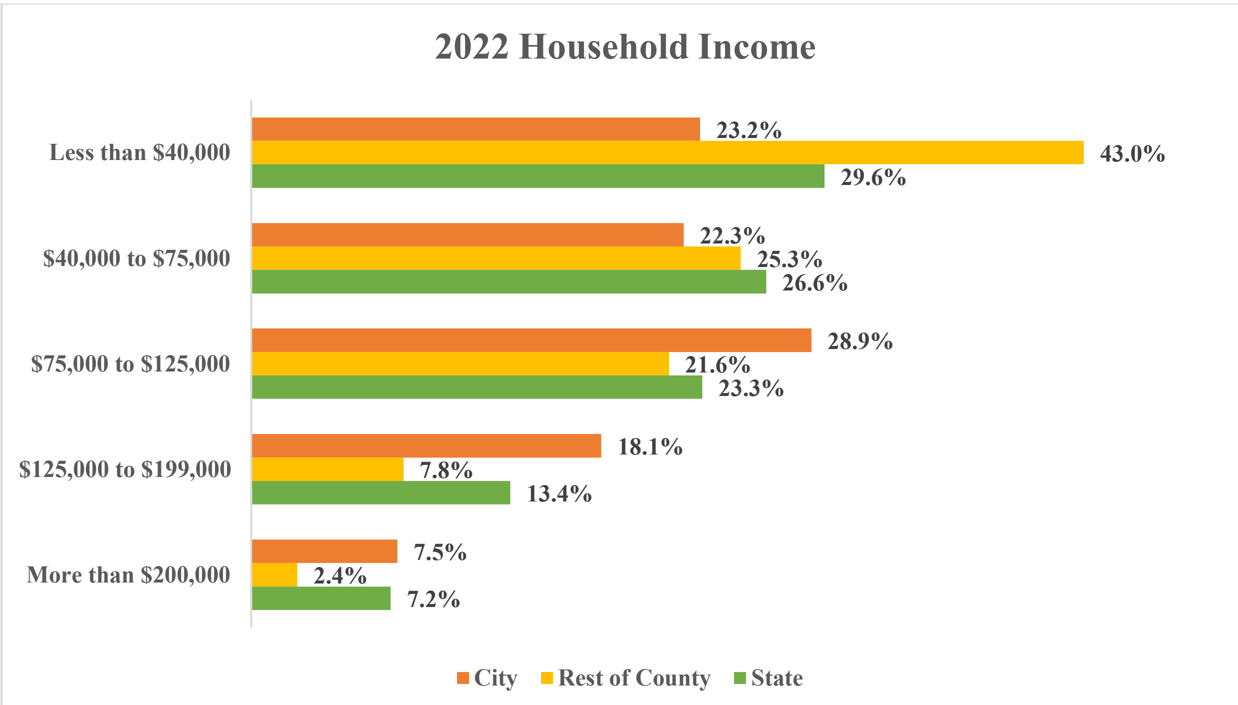
About This Study

This study was produced by Patrick M. Barkey, Ph.D., who has been retained by Baker Botts and Baker & Hostetler LLP. The research was conducted in June of 2024. The study has benefited from operational and financial information on actual operations of both the Colstrip SES and the Rosebud Mine provided by the facilities themselves. All findings of this study, as well as any errors or omissions, are solely the responsibility of Dr. Barkey, who produced all the research findings in this report.

The Colstrip SES and the Rosebud Mine

The city of Colstrip in Rosebud County in southeast Montana is home to two of the largest and highest paying industrial facilities in the entire state – the Colstrip SES and the Rosebud Mine. The economic prosperity that is enjoyed in the community today because of the presence of these major employers is evident from the earnings data from the American Community Survey conducted by the Census Bureau shown in Figure 1.

Figure 1



Compared to the state and especially to the remainder of Rosebud County, household income in the city of Colstrip is tilted to the upper side of the income distribution. Almost 29 percent of Colstrip households earn between $75,000 and $125,000 in annual income. All the earnings categories shown in the Figure above those amounts contain higher percentages of Colstrip households than elsewhere as well, which stands in stark contrast to most other communities in the eastern third of Montana.

Summary of Findings

The basic finding of this research is that the premature closure of the Colstrip SES (which also necessitates the closure of the adjacent Rosebud Mine) would be a significant setback for the economy of the state of Montana. Based on a comparison of economic activity that is projected under a status quo, no-closure scenario, the research shows that an economy where the closures take place is smaller by:

- 3,262 permanent, year-round jobs in the year 2028, the first full year of closure for the mine and the generating station. The lost jobs occur across a wide spectrum of industries and occupations.

- $240.3 million dollars in income received by households during the year 2028, due to the loss of jobs and people in the smaller state economy that results from the closure of the facilities. The loss of $203.4 million in disposable, after tax, income received by households in 2028 represents a considerable decline in spending power in local economies throughout the state.

- Over a billion dollars in economic output, generally defined as gross receipts of business and non-business organizations. The loss of revenue from sales is felt by every industry in the economy, from health care to retail sales.

- $102.8 million in selected tax and non-tax revenues to Montana state government in 2028, due not only to the reduction in the size of the overall economy, but also to the loss of specific tax revenue from coal and utility operations in the wake of closures at the Colstrip SES and the Rosebud Mine.

- 1,305 people in 2028, growing to more than 4,100 people in year 2040, who leave the state due to the loss of economic opportunity due to MATS rulemaking-induced closures in Colstrip.

Table 1

The Economic Implications of MATS Rulemaking in Montana
Impacts Summary

		Impacts by Year		
Category	**Units**	**2028**	**2035**	**2040**
Total Employment	Jobs	-3,262	-3,020	-2,890
Personal Income	$ Millions*	-240.3	-284.8	-310.0
Disposable Personal Income	$ Millions*	-203.4	-244.9	-268.5
Selected State Revenues	$ Millions*	-102.8	-120.4	-126.8
Output	$ Millions*	-1,011.4	-1,006.3	-1,016.8
Population	People	-1,305	-3,647	-4,106

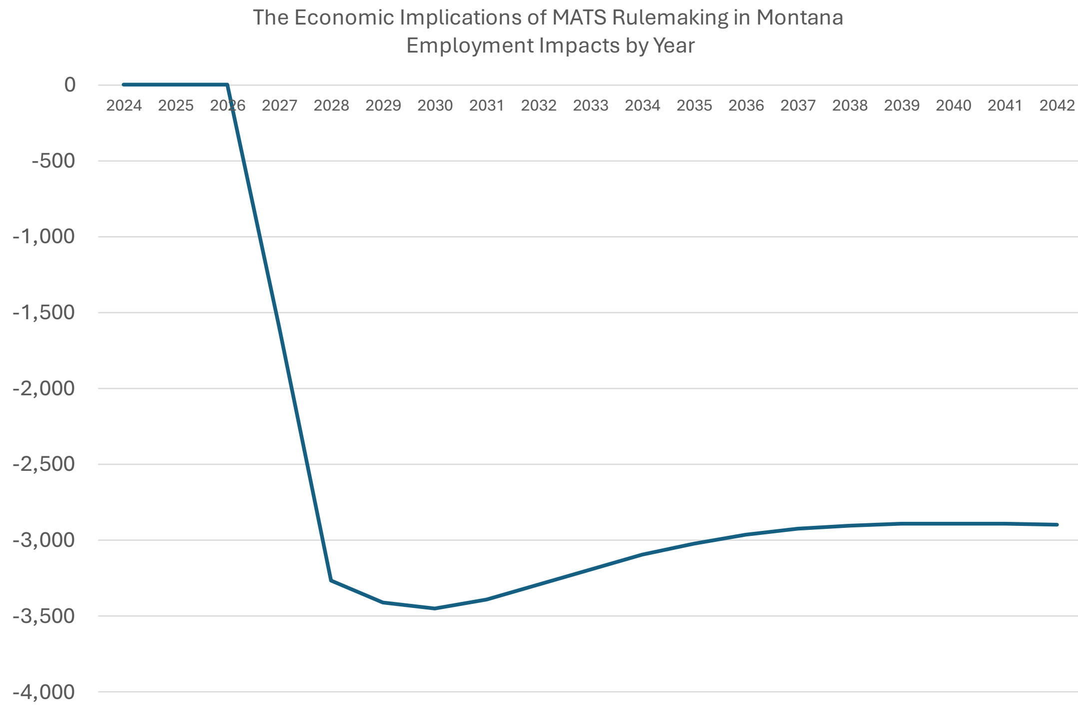
*All dollar amounts are inflation-corrected, expressed in terms of 2024 dollars.

Each of these specific impacts represent the difference in economic activity between a status quo, no closure economy and the economy that is expected to emerge after the closure of the Colstrip SES and the Rosebud Mine.

As shown in Table 1, the impacts of MATS rulemaking are expected to evolve over time over the next 15 years. These changes over time are the product of several different forces. Productivity gains over time slightly reduce the expected employment losses but result in income losses that are larger. The out-migration of Montanans who leave for other states (or those who would move here except for the closures) rises over time, with deleterious effects on everything from income to tax revenues.

The evolution of these impacts is shown graphically in Figure 2 for employment impacts. With the closures assumed to take place at the midpoint of year 2027, the first year with ceased operations at the mine and the generation station is 2028. Employment impacts grow in absolute value beyond that year as industries like construction suffer from the oversupply of structures. The low point is the year 2030, when employment impacts are 3.486 jobs.

Figure 2



As is the case for most situations where jobs are created or lost in a regional economy, the number of jobs ultimately lost in the overall economy shown in Figure 2 exceeds the number of jobs eliminated at the mine and the generating station due to their closure. These knock-on effects in the overall economy occur as the lost revenue of those who previously received the employee and vendor spending of the facilities propagates through their own spending and employment. Nonetheless, the additional job losses that are expected to occur in the wake of MATS rulemaking-induced closures in Colstrip are large.

Three factors account for the magnitude of job losses that occur.

The first is the nature of the jobs at the mine and the generating station. These are capital-intensive, high value-added businesses that compensate their employees very well – average compensation at each facility is more than twice as high as the Montana average earnings per job.

Secondly, the production of coal and electricity involves a high fraction of inputs that are made in Montana. Thus, vendor spending of the facilities is more likely to be directed within the state, instead of being lost to the economy when purchases of goods and services are directed to suppliers located elsewhere.

Finally, there is the special tax treatment of production in natural resources in Montana, especially coal mining. Table 1 shows state revenue losses exceeding $100 million as a result of closures of the mine and generating station. These revenue losses result in a loss of government spending or possibly higher tax rates on the rest of the economy, which contribute to lower employment as well.

The impacts on the state economy that are caused by the MATS rulemaking-induced closure of the Colstrip SES and the adjacent Rosebud Mine that are summarized in Table 1 are sizable, yet they are likely to understate the losses that actually occur. This is because this analysis does not take into account other factors and events that would occur in the wake of the loss of the state's largest producer of electricity. These include:

- The implications of the loss of property tax revenues to local governments
- The electricity rate implications of the stranded capital costs borne by the Montana investor-owned utility that is partial owner of the Colstrip SES
- The implications for pricing and reliability of electricity supply as Colstrip generation is lost
- The cost of building replacement generation

None of these factors are considered in the closure analysis presented here.

Detailed Findings

Further insights on how the overall decline in the state economy caused by the MATS rulemaking-induced closures of the Colstrip SES and the Rosebud Mine can be gleaned from an examination of the impacts in greater detail.

Tables 2-7 on the following pages report on impacts for employment by industry, personal income, compensation and earnings, economic output, selected state tax and non-tax revenues, and population, respectively.

The employment impacts in Table 2 clearly show how the losses in utility and mining employment associated directly with the closures in Colstrip propagate to the broader economy.

Table 2

The Economic Implications of MATS Rulemaking in Montana
Employment Impacts (Jobs)

Industry	Impacts by Year 2028	2035	2040
Construction	-592	-362	-254
Manufacturing	-44	-27	-23
Mining	-328	-323	-319
Utilities	-270	-266	-265
Retail Trade	-260	-242	-230
Transportation and Warehousing	-66	-52	-49
Professional and Technical Services	-171	-164	-160
Administrative and Waste Services	-163	-147	-141
Health Care and Social Assistance	-196	-174	-184
Arts, Entertainment, and Recreation	-49	-36	-37
Accommodation and Food Services	-169	-199	-212
Other Services, except Public Administration	-130	-115	-116
Other	-823	-913	-898
Total	**-3,262**	**-3,020**	**-2,890**

Personal income is the income received by households. The detail on the components of the impacts on personal income shown in Table 3 reveals that while most of the losses stem from declines in earnings related to job losses, there are also sizable impacts on non-labor source of income that results from the smaller post-closure economy.

Table 3

The Economic Implications of MATS Rulemaking in Montana
Personal Income Impacts (Millions of Dollars*)

Category		Impacts by Year 2028	2035	2040
Total Earnings by Place of Work		**-275.4**	**-274.8**	**-273.2**
	Total Wage and Salary Disbursements	-188.4	-192.1	-192.2
	Supplements to Wages and Salaries	-49.6	-58.3	-60.5
	Employer contributions for employee pension and insurance funds	-31.6	-37.2	-38.6
	Employer contributions for government social insurance	-17.9	-21.1	-21.9
	Proprietors' income with inventory valuation and capital consumption adjustments	-37.4	-24.4	-20.5
Less:				
	Contributions for government social insurance	-37.1	-39.9	-40.2
	Employee and self-employed contributions for government social insurance	-19.1	-18.8	-18.4
	Employer contributions for government social insurance	-17.9	-21.1	-21.9
Plus:				
	Adjustment for residence	0.7	0.7	0.6
	Gross In	0.1	0.3	0.3
	Gross Out	-0.6	-0.4	-0.4
Equals:	**Net earnings by place of residence**	**-237.6**	**-234.2**	**-232.3**
Plus:				
	Property Income	-7.9	-31.4	-42.6
	Dividends	-3.4	-13.7	-18.7
	Interest	-2.9	-11.5	-15.3
	Rent	-1.5	-6.3	-8.6
	Personal Current Transfer Receipts	5.1	-19.1	-35.2
Equals:	**Personal Income**	**-240.3**	**-284.8**	**-310.0**
Less:				
	Personal Current Taxes	-36.8	-40.0	-41.5
Equals:	**Disposable Personal Income**	**-203.4**	**-244.9**	**-268.5**

*All dollar amounts are inflation-corrected, expressed in terms of 2024 dollars.

The additional detail on wages, compensation and earnings impacts shown in Table 4 show how income losses are borne by both wage and salary workers as well as business proprietors. The average earnings for the total of all jobs lost, as shown in the table, far exceeds the average earnings of jobs overall in Montana.

Table 4

The Economic Implications of MATS Rulemaking in Montana Earnings and Compensation Impacts (Millions of Dollars)*

Category	Units	Impacts by Year 2028	2035	2040
Wages and Salaries	$ Millions	-$188.4	-$192.1	-$192.2
Compensation	$ Millions	-$238.0	-$250.4	-$252.7
Earnings	$ Millions	-$275.4	-$274.8	-$273.2
Earnings per Job, Lost Jobs	$ Dollars	$84,425	$91,017	$94,520

*All dollar amounts are inflation-corrected, expressed in terms of 2024 dollars.

Economic output is defined as gross receipts of business and non-business organizations, with the exception of retail and wholesale trade, where markup is used. The output impacts in Table 5 show how the revenues of Montana industries are significantly affected by closures occurring in Colstrip. Including the lost revenues of the mine and generating station, these exceed $1 billion.

Table 5

The Economic Implications of MATS Rulemaking in Montana Output Impacts (Millions of Dollars)*

Industry	Impacts by Year 2028	2035	2040
Construction	-95.7	-64.6	-48.1
Manufacturing	-30.5	-18.0	-15.7
Utilities	-310.9	-324.7	-335.9
Mining	-258.5	-254.4	-252.4
Retail Trade	-31.2	-35.8	-39.3
Transportation and Warehousing	-16.9	-14.1	-14.4
Professional and Technical Services	-28.9	-32.4	-34.6
Administrative and Waste Services	-18.6	-19.7	-20.7
Health Care and Social Assistance	-29.5	-31.0	-35.8
Arts, Entertainment, and Recreation	-4.4	-3.6	-3.8
Accommodation and Food Services	-16.5	-20.6	-23.2
Other Services, except Public Administration	-9.8	-9.8	-10.4
Other Private	-94.4	-88.4	-92.1
Government	-65.5	-89.2	-90.4
TOTAL	**-$1,011.4**	**-$1,006.3**	**-$1,016.8**

*All dollar amounts are inflation-corrected, expressed in terms of 2024 dollars.

The smaller economy that results from the MATS rulemaking-induced closures in Colstrip yields a lower revenue base for the state. Revenues are also affected by the loss of production taxes at the Rosebud Mine and the Colstrip SES, which are categorized as selected sales taxes shown in Table 6. Not all revenue sources shown in the table are general fund revenues subject to the discretion of the legislature. Taken as a whole, they exceed $100 million per year.

Table 6

The Economic Implications of MATS Rulemaking in Montana
Selected State Revenue Impacts (Millions of Dollars*)

Category	Impacts by Year 2028	2035	2040
Intergovernmental Revenue	-5.3	-14.9	-16.8
Selective Sales Tax	-46.9	-47.3	-47.5
License Taxes	-1.1	-1.3	-1.4
Individual Income Tax	-10.7	-11.6	-12.0
Corporate Income Tax	-3.4	-3.4	-3.4
Other Taxes	-2.6	-3.0	-3.3
Current Charges	-3.5	-4.1	-4.5
Miscellaneous General Revenue	-2.8	-3.3	-3.6
Utility Revenue	-0.3	-0.3	-0.4
Liquor Store Revenue	-0.7	-0.8	-0.8
Insurance Trust Revenue	-25.6	-30.3	-33.0
Total	**-$102.8**	**-$120.4**	**-$126.8**

*All dollar amounts are inflation-corrected, expressed in terms of 2024 dollars.

An important factor in all of these detailed impacts is the change in population that is expected to occur due to the closures in Colstrip. This is not a prediction of overall population decline, but a population level that is lower than what would have occurred if the closures did not take place. As shown in Table 7, the population impacts increase substantially over time, and are dominated by those of working age and their children.

Table 7

The Economic Implications of MATS Rulemaking in Montana Population Impacts (People)

	Impacts by Year		
Age Cohort	2028	2035	2040
Ages 0-14	-318	-923	-1,014
Ages 15-24	-279	-452	-507
Ages 25-64	-707	-2,192	-2,421
Ages 65+	-2	-81	-164
Total	-1,305	-3,647	-4,106

Conclusion

This report has summarized and documented the findings of an analysis of the economic implications of the MATS rulemaking in Montana. Specifically, it addresses how the MATS rulemaking-induced closure of the Colstrip Steam Electric Station (SES) in Rosebud County in southeast Montana due to the physical or economic infeasibility of meeting the reduced mercury emission threshold in the new final MATS rule would affect the economy of the state. The potential for economic harm from the rulemaking is made greater due to the tight coupling between the Colstrip SES and the immediately adjacent Rosebud Mine that serves the generation station with its coal supply via conveyor belt. This is because without substantial new development in rail infrastructure, the continued production of coal with the closure of the generating station would be impossible and its closure would occur as well.

The basic finding of this study is that implementation of the new MATS standard would be a significant negative event for the Montana economy. The loss of the high-paying jobs at the two facilities, and the cessation of the significant vendor spending and tax revenues associated with their operation, would ultimately precipitate a loss of 3,262 jobs in 2028, the first full year of closure after the new standards take effect. This impact represents the difference between what employment in the state would have been in a no-closure scenario and the post-closure job total. This employment impact grows to 3,446 jobs in 2030.

Other dimensions of economic vitality are presented in this report. All underscore the overall conclusion that a Montana economy that is required to meet the final rule of the U.S. Environmental Protection Agency's MATS regulation is smaller, less prosperous, and less populous than would occur if the current rules remained in effect.

References

Bureau of Business and Economic Research. (2018). *The Economic Impact of the Early Retirement of Colstrip Units 3 and 4.* Montana Chamber Foundation.

Cassing, S., & Giaratini, F. (1992). An evaluation of the REMI model for the south coast air quality management district. *Environment and Planning*, 1549-1564.

Appendix A

REMI Model Output

MATS rulemaking impacts - Economic Summary

Category	Units	Year 2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Employment	Individuals (Jobs)	+1594.041	+3261.849	+3410.891	+3446.125	+3389.968	+3293.942	+3190.278	+3095.574	+3019.627
Private Non-Farm Employment	Individuals (Jobs)	+1393.358	+2812.036	+2883.827	+2879.690	+2806.039	+2704.940	+2602.380	+2511.644	+2440.535
Residence Adjusted Employment	Individuals	+1571.381	+3213.912	+3360.700	+3398.749	+3346.757	+3255.275	+3155.877	+3064.884	+2991.982
Population	Individuals	+477.798	+1304.930	+1939.678	+2440.929	+2825.319	+3117.124	+3338.788	+3510.243	+3647.479
Labor Force	Individuals	+496.955	+1263.372	+1732.339	+2047.700	+2239.303	+2344.044	+2392.071	+2406.748	+2404.735
Gross Domestic Product	Millions of Fixed (2024) Dollars	+293.755	+598.871	+617.674	+625.960	+624.810	+618.904	+612.264	+605.805	+601.061
Output	Millions of Fixed (2024) Dollars	+497.178	+1011.370	+1040.713	+1051.794	+1047.385	+1036.244	+1024.039	+1013.485	+1006.302
Value-Added	Millions of Fixed (2024) Dollars	+293.755	+598.871	+617.674	+625.960	+624.810	+618.904	+612.264	+605.805	+601.061
Personal Income	Millions of Fixed (2024) Dollars	+119.838	+240.285	+250.333	+264.052	+271.624	+276.149	+279.155	+281.830	+284.805
Disposable Personal Income	Millions of Fixed (2024) Dollars	+101.413	+203.446	+212.042	+224.263	+231.361	+235.993	+239.093	+241.781	+244.851
Real Disposable Personal Income	Millions of Fixed (2017) Dollars	+82.710	+165.926	+172.936	+182.903	+188.692	+192.470	+194.999	+197.191	+199.695
Real Disposable Personal Income per Capita	Thousands of Fixed (2017) Dollars	+0.051	+0.089	+0.070	+0.058	+0.047	+0.038	+0.030	+0.023	+0.018
PCE-Price Index	2017=100 (Nation)	+0.004	+0.035	+0.065	+0.070	+0.073	+0.073	+0.073	+0.072	+0.071

Comparison Type: Montana - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

MATS rulemaking impacts - Economic Summary

Category	Units	Year 2036	2037	2038	2039	2040	2041	2042	2043	2044
Total Employment	Individuals (Jobs)	+2963.090	+2925.639	+2903.554	+2893.035	+2890.194	+2892.077	+2895.790	+2899.300	+2901.801
Private Non-Farm Employment	Individuals (Jobs)	+2388.557	+2354.860	+2335.845	+2327.745	+2326.908	+2330.537	+2335.892	+2341.091	+2345.424
Residence Adjusted Employment	Individuals	+2937.840	+2902.210	+2881.463	+2871.916	+2869.777	+2872.174	+2876.279	+2880.111	+2882.894
Population	Individuals	+3761.717	+3860.652	+3949.665	+4031.275	+4106.385	+4175.468	+4238.252	+4293.884	+4341.941
Labor Force	Individuals	+2395.987	+2387.183	+2381.338	+2379.340	+2381.361	+2386.388	+2393.607	+2402.356	+2411.168
Gross Domestic Product	Millions of Fixed (2024) Dollars	+598.367	+597.631	+598.436	+600.503	+603.306	+606.575	+610.113	+613.626	+616.890
Output	Millions of Fixed (2024) Dollars	+1002.551	+1002.198	+1004.923	+1010.001	+1016.793	+1024.776	+1033.363	+1042.124	+1050.881
Value-Added	Millions of Fixed (2024) Dollars	+598.367	+597.631	+598.436	+600.503	+603.306	+606.575	+610.113	+613.626	+616.890
Personal Income	Millions of Fixed (2024) Dollars	+288.394	+292.810	+298.006	+303.836	+310.033	+316.507	+323.079	+329.599	+335.949
Disposable Personal Income	Millions of Fixed (2024) Dollars	+248.403	+252.624	+257.483	+262.860	+268.530	+274.417	+280.373	+286.267	+292.001
Real Disposable Personal Income	Millions of Fixed (2017) Dollars	+202.591	+206.034	+209.997	+214.382	+219.006	+223.808	+228.665	+233.472	+238.149
Real Disposable Personal Income per Capita	Thousands of Fixed (2017) Dollars	+0.015	+0.011	+0.009	+0.007	+0.005	+0.004	+0.003	+0.002	+0.001
PCE-Price Index	2017=100 (Nation)	+0.070	+0.069	+0.069	+0.069	+0.070	+0.070	+0.071	+0.072	+0.072

Comparison Type: Montana - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

MATS rulemaking impacts - Industry Profile

		Year								
Industry	Units	2027	2028	2029	2030	2031	2032	2033	2034	2035
All Industries	**Individuals (Jobs)**	**+1594.041**	**+3261.849**	**+3410.891**	**+3446.125**	**+3389.968**	**+3293.942**	**+3190.278**	**+3095.574**	**+3019.627**
Forestry and Logging; Fishing, hunting and trap	Individuals (Jobs)	+0.686	+1.226	+0.960	+0.680	+0.404	+0.167	-0.035	-0.181	-0.278
Support activities for agriculture and forestry	Individuals (Jobs)	+0.329	+0.474	+0.107	-0.252	-0.575	-0.822	-1.051	-1.202	-1.298
Oil and gas extraction	Individuals (Jobs)	+0.405	+0.689	+0.504	+0.350	+0.228	+0.149	+0.106	+0.098	+0.109
Mining (except oil and gas)	Individuals (Jobs)	+164.007	+328.274	+327.594	+326.943	+326.364	+326.019	+324.593	+323.471	+322.512
Support activities for mining	Individuals (Jobs)	+45.385	+90.342	+89.727	+89.098	+88.471	+87.904	+87.400	+86.965	+86.589
Utilities	Individuals (Jobs)	+135.242	+269.938	+269.310	+268.778	+268.241	+267.713	+267.241	+266.814	+266.460
Construction	Individuals (Jobs)	+273.560	+592.224	+656.048	+650.076	+603.458	+539.353	+472.701	+412.014	+361.841
Wood product manufacturing	Individuals (Jobs)	+4.657	+9.679	+10.141	+9.635	+8.596	+7.395	+6.237	+5.234	+4.437
Nonmetallic mineral product manufacturing	Individuals (Jobs)	+1.286	+2.644	+2.725	+2.588	+2.330	+2.033	+1.747	+1.497	+1.296
Primary metal manufacturing	Individuals (Jobs)	+0.284	+0.562	+0.555	+0.536	+0.510	+0.491	+0.461	+0.440	+0.423
Fabricated metal product manufacturing	Individuals (Jobs)	+3.060	+6.188	+6.281	+6.028	+5.576	+5.087	+4.582	+4.157	+3.816
Machinery manufacturing	Individuals (Jobs)	+0.570	+1.136	+1.152	+1.103	+1.023	+0.950	+0.817	+0.711	+0.624
Computer and electronic product manufacturin	Individuals (Jobs)	+0.294	+0.463	+0.202	-0.091	-0.382	-0.641	-0.844	-1.002	-1.118
Electrical equipment, appliance, and component	Individuals (Jobs)	+0.003	-0.003	-0.020	-0.038	-0.054	-0.067	-0.078	-0.087	-0.093
Motor vehicles, bodies and trailers, and parts r	Individuals (Jobs)	+0.734	+1.503	+1.599	+1.623	+1.603	+1.570	+1.518	+1.471	+1.430
Other transportation equipment manufacturing	Individuals (Jobs)	+0.222	+0.443	+0.452	+0.442	+0.421	+0.398	+0.381	+0.367	+0.356
Furniture and related product manufacturing	Individuals (Jobs)	+1.817	+3.601	+3.611	+3.488	+3.257	+3.003	+2.779	+2.596	+2.461
Miscellaneous manufacturing	Individuals (Jobs)	+0.646	+1.145	+0.912	+0.679	+0.449	+0.247	+0.084	-0.040	-0.129
Food manufacturing	Individuals (Jobs)	+2.958	+5.952	+6.143	+6.241	+6.204	+6.134	+6.010	+5.921	+5.867
Beverage and tobacco manufacturing	Individuals (Jobs)	+2.042	+4.213	+4.619	+4.940	+5.117	+5.210	+5.239	+5.247	+5.247
Textile mills and textile product mills	Individuals (Jobs)	+0.305	+0.571	+0.516	+0.442	+0.356	+0.274	+0.203	+0.147	+0.108
Apparel, leather and allied product manufacturi	Individuals (Jobs)	+0.222	+0.323	+0.112	-0.088	-0.273	-0.418	-0.520	-0.588	-0.626
Paper manufacturing	Individuals (Jobs)	+0.036	+0.071	+0.070	+0.068	+0.065	+0.061	+0.057	+0.054	+0.052
Printing and related support activities	Individuals (Jobs)	+0.304	+0.568	+0.507	+0.438	+0.368	+0.306	+0.256	+0.218	+0.191
Petroleum and coal products manufacturing	Individuals (Jobs)	+0.968	+1.820	+1.635	+1.440	+1.251	+1.082	+0.942	+0.835	+0.749
Chemical manufacturing	Individuals (Jobs)	+0.280	+0.505	+0.415	+0.327	+0.244	+0.171	+0.106	+0.054	+0.013
Plastics and rubber products manufacturing	Individuals (Jobs)	+1.530	+3.050	+3.073	+2.998	+2.859	+2.717	+2.565	+2.441	+2.339
Wholesale trade	Individuals (Jobs)	+33.208	+65.057	+64.231	+62.228	+59.172	+55.989	+53.224	+50.988	+49.219
Retail trade	Individuals (Jobs)	+129.909	+259.946	+267.649	+270.333	+266.420	+259.614	+252.877	+246.710	+241.774

		Year								
Industry	Units	2027	2028	2029	2030	2031	2032	2033	2034	2035
Air transportation	Individuals (Jobs)	+1.423	+2.763	+2.698	+2.590	+2.452	+2.314	+2.207	+2.121	+2.057
Rail transportation	Individuals (Jobs)	+0.520	+0.773	+0.309	-0.093	-0.423	-0.669	-0.856	-0.975	-1.047
Water transportation	Individuals (Jobs)	+0.026	+0.052	+0.051	+0.050	+0.049	+0.049	+0.046	+0.045	+0.044
Truck transportation	Individuals (Jobs)	+11.822	+23.719	+23.949	+23.600	+22.845	+22.072	+21.027	+20.215	+19.555
Couriers and messengers	Individuals (Jobs)	+3.559	+6.803	+6.228	+5.585	+4.899	+4.279	+3.746	+3.350	+3.077
Transit and ground passenger transportation	Individuals (Jobs)	+3.767	+7.740	+8.068	+8.158	+8.086	+7.934	+7.776	+7.641	+7.554
Pipeline transportation	Individuals (Jobs)	+1.530	+2.935	+2.741	+2.568	+2.418	+2.332	+2.234	+2.194	+2.170
Scenic and sightseeing transportation and supp	Individuals (Jobs)	+8.507	+16.811	+16.489	+16.148	+15.797	+15.533	+15.156	+14.892	+14.675
Warehousing and storage	Individuals (Jobs)	+1.988	+3.965	+3.952	+3.900	+3.805	+3.696	+3.601	+3.518	+3.456
Publishing industries, except Internet	Individuals (Jobs)	+0.015	-0.091	-0.322	-0.531	-0.711	-0.854	-0.965	-1.044	-1.096
Motion picture and sound recording industries	Individuals (Jobs)	+0.441	+0.871	+0.864	+0.837	+0.796	+0.756	+0.723	+0.701	+0.691
Data processing, hosting, and related services;	Individuals (Jobs)	+1.107	+2.263	+2.360	+2.415	+2.428	+2.421	+2.407	+2.386	+2.366
Radio and television broadcasting, media strea	Individuals (Jobs)	+0.598	+1.208	+1.252	+1.273	+1.272	+1.263	+1.253	+1.245	+1.242
Telecommunications	Individuals (Jobs)	+0.992	+1.898	+1.774	+1.626	+1.469	+1.325	+1.208	+1.118	+1.056
Monetary authorities - central bank, credit inte	Individuals (Jobs)	+1.379	+1.809	+0.110	-1.378	-2.647	-3.647	-4.403	-4.937	-5.278
Securities, commodity contracts, investments,	Individuals (Jobs)	+14.847	+28.911	+27.763	+26.219	+24.539	+23.037	+21.728	+20.763	+20.107
Insurance carriers and related activities	Individuals (Jobs)	+2.679	+5.144	+4.802	+4.460	+4.124	+3.858	+3.636	+3.510	+3.455
Real estate	Individuals (Jobs)	+75.528	+149.376	+154.927	+162.115	+163.591	+162.508	+160.463	+158.736	+157.891
Rental and leasing services; Lessors of nonfin	Individuals (Jobs)	+7.789	+15.374	+15.245	+14.878	+14.320	+13.692	+13.077	+12.527	+12.073
Professional, scientific, and technical services	Individuals (Jobs)	+83.712	+171.036	+177.688	+179.282	+177.422	+173.753	+170.498	+167.149	+164.466
Management of companies and enterprises	Individuals (Jobs)	+0.041	-0.010	-0.186	-0.341	-0.471	-0.574	-0.652	-0.707	-0.743
Administrative and support services	Individuals (Jobs)	+84.109	+167.703	+167.871	+166.866	+164.347	+160.812	+157.713	+154.485	+151.860
Waste management and remediation services	Individuals (Jobs)	-2.536	-4.911	-4.696	-4.600	-4.594	-4.624	-4.654	-4.672	-4.664
Educational services; private	Individuals (Jobs)	+4.540	+8.936	+8.887	+8.740	+8.425	+8.072	+7.773	+7.543	+7.399
Ambulatory health care services	Individuals (Jobs)	+58.956	+111.059	+104.169	+100.515	+96.008	+91.894	+88.948	+86.862	+85.711
Hospitals	Individuals (Jobs)	+18.429	+37.002	+38.575	+40.012	+40.660	+40.981	+41.217	+41.514	+41.941
Nursing and residential care facilities	Individuals (Jobs)	+5.893	+11.527	+11.418	+11.313	+11.041	+10.764	+10.545	+10.417	+10.391
Social assistance	Individuals (Jobs)	+18.637	+36.849	+37.063	+37.247	+36.879	+36.365	+35.963	+35.764	+35.827
Performing arts, spectator sports, and related	Individuals (Jobs)	+8.230	+15.307	+13.952	+13.031	+12.054	+11.187	+10.492	+9.980	+9.654
Museums, historical sites, and similar instituti	Individuals (Jobs)	+0.044	+0.033	-0.065	-0.151	-0.224	-0.282	-0.327	-0.359	-0.380
Amusement, gambling, and recreation industrie	Individuals (Jobs)	+17.998	+33.861	+31.897	+31.010	+29.816	+28.660	+27.734	+27.060	+26.670

		Year								
Industry	Units	2027	2028	2029	2030	2031	2032	2033	2034	2035
Accommodation	Individuals (Jobs)	+18.283	+34.261	+32.335	+31.864	+31.097	+30.411	+29.952	+29.776	+29.904
Food services and drinking places	Individuals (Jobs)	+66.531	+134.894	+143.631	+152.770	+158.507	+162.150	+164.725	+166.727	+168.631
Repair and maintenance	Individuals (Jobs)	+16.162	+32.536	+33.889	+34.876	+35.055	+34.846	+34.509	+34.184	+33.963
Personal and laundry services	Individuals (Jobs)	+25.537	+48.474	+46.544	+46.451	+45.740	+44.952	+44.302	+43.853	+43.663
Religious, grantmaking, civic, professional, and	Individuals (Jobs)	+22.458	+43.184	+41.793	+40.682	+39.135	+37.576	+36.242	+35.188	+34.451
Private households	Individuals (Jobs)	+2.867	+5.370	+4.971	+4.669	+4.329	+4.008	+3.737	+3.524	+3.369
State and Local Government	Individuals (Jobs)	+200.645	+449.739	+526.989	+566.359	+583.854	+588.927	+587.823	+583.857	+579.019
Federal Civilian	Individuals (Jobs)	+0.024	+0.048	+0.048	+0.048	+0.048	+0.048	+0.047	+0.047	+0.047
Federal Military	Individuals (Jobs)	+0.014	+0.027	+0.027	+0.027	+0.027	+0.027	+0.027	+0.027	+0.027
Farm	Individuals (Jobs)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Category: Montana - Comparison Type: Employment - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

MATS rulemaking impacts - Industry Profile

		Year								
Industry	Units	2036	2037	2038	2039	2040	2041	2042	2043	2044
All Industries	**Individuals (Jobs)**	**+2963.090**	**+2925.639**	**+2903.554**	**+2893.035**	**+2890.194**	**+2892.077**	**+2895.790**	**+2899.300**	**+2901.801**
Forestry and Logging; Fishing, hunting and trap	Individuals (Jobs)	-0.334	-0.357	-0.358	-0.343	-0.319	-0.290	-0.259	-0.228	-0.199
Support activities for agriculture and forestry	Individuals (Jobs)	-1.350	-1.370	-1.366	-1.348	-1.320	-1.287	-1.252	-1.218	-1.185
Oil and gas extraction	Individuals (Jobs)	+0.134	+0.169	+0.212	+0.260	+0.312	+0.366	+0.422	+0.478	+0.534
Mining (except oil and gas)	Individuals (Jobs)	+321.685	+320.967	+320.332	+319.763	+319.231	+318.739	+318.275	+317.831	+317.407
Support activities for mining	Individuals (Jobs)	+86.263	+85.984	+85.743	+85.535	+85.350	+85.187	+85.038	+84.902	+84.775
Utilities	Individuals (Jobs)	+266.159	+265.908	+265.695	+265.507	+265.329	+265.162	+264.998	+264.834	+264.669
Construction	Individuals (Jobs)	+322.938	+294.629	+275.151	+262.445	+254.494	+249.726	+246.735	+244.540	+242.590
Wood product manufacturing	Individuals (Jobs)	+3.842	+3.428	+3.162	+3.005	+2.921	+2.887	+2.881	+2.885	+2.891
Nonmetallic mineral product manufacturing	Individuals (Jobs)	+1.143	+1.032	+0.957	+0.907	+0.876	+0.857	+0.844	+0.835	+0.827
Primary metal manufacturing	Individuals (Jobs)	+0.410	+0.401	+0.394	+0.390	+0.386	+0.383	+0.380	+0.378	+0.376
Fabricated metal product manufacturing	Individuals (Jobs)	+3.557	+3.371	+3.246	+3.163	+3.109	+3.073	+3.050	+3.032	+3.016
Machinery manufacturing	Individuals (Jobs)	+0.556	+0.504	+0.464	+0.432	+0.425	+0.422	+0.421	+0.421	+0.422
Computer and electronic product manufacturin	Individuals (Jobs)	-1.200	-1.254	-1.288	-1.306	-1.314	-1.314	-1.310	-1.303	-1.294
Electrical equipment, appliance, and component	Individuals (Jobs)	-0.097	-0.100	-0.102	-0.103	-0.104	-0.104	-0.104	-0.103	-0.103
Motor vehicles, bodies and trailers, and parts r	Individuals (Jobs)	+1.397	+1.372	+1.352	+1.336	+1.323	+1.311	+1.301	+1.291	+1.281
Other transportation equipment manufacturing	Individuals (Jobs)	+0.349	+0.344	+0.342	+0.341	+0.342	+0.343	+0.344	+0.346	+0.347
Furniture and related product manufacturing	Individuals (Jobs)	+2.368	+2.313	+2.288	+2.287	+2.302	+2.328	+2.360	+2.392	+2.424
Miscellaneous manufacturing	Individuals (Jobs)	-0.190	-0.229	-0.250	-0.258	-0.259	-0.253	-0.245	-0.234	-0.223
Food manufacturing	Individuals (Jobs)	+5.842	+5.847	+5.866	+5.896	+5.928	+5.955	+5.973	+5.978	+5.968
Beverage and tobacco manufacturing	Individuals (Jobs)	+5.245	+5.246	+5.253	+5.258	+5.258	+5.253	+5.244	+5.229	+5.209
Textile mills and textile product mills	Individuals (Jobs)	+0.082	+0.068	+0.060	+0.057	+0.058	+0.060	+0.063	+0.066	+0.070
Apparel, leather and allied product manufacturi	Individuals (Jobs)	-0.638	-0.629	-0.605	-0.572	-0.534	-0.495	-0.456	-0.418	-0.383
Paper manufacturing	Individuals (Jobs)	+0.050	+0.049	+0.048	+0.047	+0.047	+0.046	+0.046	+0.046	+0.045
Printing and related support activities	Individuals (Jobs)	+0.174	+0.163	+0.158	+0.156	+0.156	+0.157	+0.158	+0.159	+0.160
Petroleum and coal products manufacturing	Individuals (Jobs)	+0.681	+0.627	+0.583	+0.547	+0.515	+0.488	+0.462	+0.438	+0.415
Chemical manufacturing	Individuals (Jobs)	-0.019	-0.045	-0.066	-0.083	-0.098	-0.110	-0.122	-0.133	-0.144
Plastics and rubber products manufacturing	Individuals (Jobs)	+2.260	+2.201	+2.158	+2.127	+2.101	+2.079	+2.060	+2.042	+2.024
Wholesale trade	Individuals (Jobs)	+47.853	+46.858	+46.166	+45.663	+45.271	+44.958	+44.671	+44.384	+44.096
Retail trade	Individuals (Jobs)	+237.862	+235.045	+232.919	+231.446	+230.376	+229.521	+228.661	+227.679	+226.589

Industry	Units	Year								
		2036	2037	2038	2039	2040	2041	2042	2043	2044
Air transportation	Individuals (Jobs)	+2.010	+1.979	+1.961	+1.952	+1.947	+1.947	+1.948	+1.949	+1.951
Rail transportation	Individuals (Jobs)	-1.082	-1.092	-1.085	-1.065	-1.039	-1.008	-0.974	-0.940	-0.905
Water transportation	Individuals (Jobs)	+0.044	+0.044	+0.043	+0.043	+0.043	+0.043	+0.043	+0.043	+0.043
Truck transportation	Individuals (Jobs)	+19.032	+18.636	+18.335	+18.108	+17.927	+17.780	+17.646	+17.516	+17.389
Couriers and messengers	Individuals (Jobs)	+2.905	+2.818	+2.798	+2.824	+2.881	+2.958	+3.044	+3.133	+3.222
Transit and ground passenger transportation	Individuals (Jobs)	+7.510	+7.509	+7.537	+7.586	+7.649	+7.720	+7.794	+7.866	+7.938
Pipeline transportation	Individuals (Jobs)	+2.157	+2.153	+2.156	+2.164	+2.175	+2.190	+2.205	+2.221	+2.238
Scenic and sightseeing transportation and supp	Individuals (Jobs)	+14.491	+14.337	+14.201	+14.080	+13.968	+13.863	+13.760	+13.657	+13.555
Warehousing and storage	Individuals (Jobs)	+3.412	+3.384	+3.369	+3.364	+3.363	+3.365	+3.368	+3.370	+3.372
Publishing industries, except Internet	Individuals (Jobs)	-1.125	-1.138	-1.140	-1.135	-1.125	-1.112	-1.097	-1.082	-1.066
Motion picture and sound recording industries	Individuals (Jobs)	+0.690	+0.696	+0.710	+0.726	+0.744	+0.762	+0.779	+0.794	+0.808
Data processing, hosting, and related services;	Individuals (Jobs)	+2.349	+2.333	+2.330	+2.330	+2.333	+2.337	+2.340	+2.342	+2.343
Radio and television broadcasting, media strea	Individuals (Jobs)	+1.244	+1.250	+1.259	+1.271	+1.283	+1.295	+1.307	+1.317	+1.326
Telecommunications	Individuals (Jobs)	+1.015	+0.993	+0.985	+0.987	+0.994	+1.005	+1.018	+1.030	+1.043
Monetary authorities - central bank, credit inte	Individuals (Jobs)	-5.472	-5.557	-5.559	-5.506	-5.417	-5.305	-5.181	-5.051	-4.918
Securities, commodity contracts, investments,	Individuals (Jobs)	+19.697	+19.500	+19.450	+19.501	+19.604	+19.742	+19.889	+20.027	+20.150
Insurance carriers and related activities	Individuals (Jobs)	+3.456	+3.505	+3.589	+3.696	+3.816	+3.944	+4.074	+4.203	+4.328
Real estate	Individuals (Jobs)	+157.957	+158.986	+160.767	+163.071	+165.674	+168.381	+171.014	+173.419	+175.545
Rental and leasing services; Lessors of nonfin	Individuals (Jobs)	+11.704	+11.416	+11.179	+10.986	+10.819	+10.673	+10.539	+10.411	+10.287
Professional, scientific, and technical services	Individuals (Jobs)	+162.500	+161.229	+160.585	+160.374	+160.379	+160.519	+160.688	+160.806	+160.840
Management of companies and enterprises	Individuals (Jobs)	-0.766	-0.779	-0.784	-0.784	-0.781	-0.776	-0.770	-0.764	-0.757
Administrative and support services	Individuals (Jobs)	+149.805	+148.289	+147.152	+146.282	+145.545	+144.894	+144.268	+143.617	+142.919
Waste management and remediation services	Individuals (Jobs)	-4.633	-4.582	-4.512	-4.430	-4.340	-4.244	-4.147	-4.051	-3.958
Educational services; private	Individuals (Jobs)	+7.330	+7.330	+7.384	+7.473	+7.589	+7.719	+7.853	+7.983	+8.111
Ambulatory health care services	Individuals (Jobs)	+85.210	+85.303	+85.859	+86.755	+87.957	+89.326	+90.719	+92.071	+93.387
Hospitals	Individuals (Jobs)	+42.494	+43.176	+43.964	+44.822	+45.704	+46.573	+47.402	+48.149	+48.795
Nursing and residential care facilities	Individuals (Jobs)	+10.453	+10.593	+10.788	+11.022	+11.273	+11.524	+11.768	+11.995	+12.208
Social assistance	Individuals (Jobs)	+36.089	+36.563	+37.226	+37.996	+38.840	+39.725	+40.603	+41.450	+42.264
Performing arts, spectator sports, and related	Individuals (Jobs)	+9.471	+9.411	+9.441	+9.529	+9.648	+9.782	+9.913	+10.028	+10.125
Museums, historical sites, and similar instituti	Individuals (Jobs)	-0.392	-0.399	-0.400	-0.399	-0.396	-0.391	-0.385	-0.379	-0.373
Amusement, gambling, and recreation industrie	Individuals (Jobs)	+26.490	+26.510	+26.682	+26.941	+27.253	+27.584	+27.898	+28.167	+28.387

Industry	Units	Year								
		2036	2037	2038	2039	2040	2041	2042	2043	2044
Accommodation	Individuals (Jobs)	+30.265	+30.840	+31.571	+32.388	+33.251	+34.119	+34.960	+35.747	+36.478
Food services and drinking places	Individuals (Jobs)	+170.501	+172.492	+174.557	+176.651	+178.727	+180.732	+182.610	+184.296	+185.799
Repair and maintenance	Individuals (Jobs)	+33.854	+33.868	+33.974	+34.140	+34.331	+34.528	+34.711	+34.864	+34.980
Personal and laundry services	Individuals (Jobs)	+43.659	+43.846	+44.159	+44.592	+45.131	+45.705	+46.267	+46.793	+47.285
Religious, grantmaking, civic, professional, and	Individuals (Jobs)	+33.957	+33.695	+33.667	+33.755	+33.914	+34.115	+34.317	+34.496	+34.643
Private households	Individuals (Jobs)	+3.256	+3.180	+3.131	+3.101	+3.083	+3.072	+3.062	+3.051	+3.037
State and Local Government	Individuals (Jobs)	+574.460	+570.706	+567.638	+565.219	+563.215	+561.470	+559.829	+558.141	+556.308
Federal Civilian	Individuals (Jobs)	+0.046	+0.046	+0.046	+0.045	+0.045	+0.045	+0.044	+0.044	+0.043
Federal Military	Individuals (Jobs)	+0.026	+0.026	+0.026	+0.026	+0.026	+0.026	+0.025	+0.025	+0.025
Farm	Individuals (Jobs)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Category: Montana - Comparison Type: Employment - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

MATS rulemaking impacts - Income Profile

Category	Units	Year 2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Earnings by Place of Work	Millions of Fixed (2024) Dollars	+136.280	+275.380	+284.758	+291.746	+291.612	+288.028	+283.222	+278.545	+274.837
Total Wages and Salaries	Millions of Fixed (2024) Dollars	+93.310	+188.418	+194.859	+200.071	+200.726	+199.099	+196.597	+194.066	+192.125
Supplements to Wages and Salaries	Millions of Fixed (2024) Dollars	+23.984	+49.596	+52.868	+55.552	+56.940	+57.614	+57.937	+58.128	+58.279
Employer contributions for employee pens	Millions of Fixed (2024) Dollars	+15.304	+31.648	+33.736	+35.449	+36.335	+36.764	+36.971	+37.092	+37.189
Employer contributions for government so	Millions of Fixed (2024) Dollars	+8.679	+17.948	+19.132	+20.103	+20.606	+20.849	+20.966	+21.036	+21.090
Proprietors' income with inventory valuatic	Millions of Fixed (2024) Dollars	+18.986	+37.367	+37.031	+36.123	+33.946	+31.314	+28.688	+26.350	+24.433
Less: Contributions for Government Social Ins	Millions of Fixed (2024) Dollars	+18.214	+37.082	+38.815	+40.219	+40.695	+40.671	+40.419	+40.110	+39.875
Employee and Self-Employed Contributions	Millions of Fixed (2024) Dollars	+9.535	+19.134	+19.683	+20.116	+20.089	+19.822	+19.453	+19.075	+18.785
Employer contributions for government so	Millions of Fixed (2024) Dollars	+8.679	+17.948	+19.132	+20.103	+20.606	+20.849	+20.966	+21.036	+21.090
Plus: Adjustment for Residence	Millions of Fixed (2024) Dollars	-0.301	-0.741	-0.893	-0.897	-0.873	-0.833	-0.789	-0.748	-0.712
Gross Inflow	Millions of Fixed (2024) Dollars	-0.014	-0.137	-0.257	-0.276	-0.285	-0.286	-0.284	-0.279	-0.274
Gross Outflow	Millions of Fixed (2024) Dollars	+0.287	+0.605	+0.636	+0.621	+0.588	+0.547	+0.506	+0.469	+0.438
Equals: Net Earnings by Place of Residence	Millions of Fixed (2024) Dollars	+117.765	+237.557	+245.049	+250.630	+250.045	+246.523	+242.014	+237.687	+234.250
Plus: Property Income	Millions of Fixed (2024) Dollars	+4.060	+7.854	+10.106	+14.852	+19.040	+22.801	+26.041	+28.882	+31.422
Personal Dividend Income	Millions of Fixed (2024) Dollars	+1.801	+3.437	+4.415	+6.467	+8.263	+9.867	+11.272	+12.525	+13.652
Personal Interest Income	Millions of Fixed (2024) Dollars	+1.466	+2.878	+3.691	+5.426	+6.976	+8.392	+9.580	+10.591	+11.486
Rental Income of Persons	Millions of Fixed (2024) Dollars	+0.793	+1.539	+2.000	+2.959	+3.801	+4.542	+5.188	+5.765	+6.284
Plus: Personal Current Transfer Receipts	Millions of Fixed (2024) Dollars	-1.986	-5.126	-4.822	-1.430	+2.539	+6.824	+11.100	+15.262	+19.133
Equals: Personal Income	Millions of Fixed (2024) Dollars	+119.838	+240.285	+250.333	+264.052	+271.624	+276.149	+279.155	+281.830	+284.805
Less: Personal current taxes	Millions of Fixed (2024) Dollars	+18.426	+36.839	+38.292	+39.789	+40.264	+40.156	+40.061	+40.049	+39.954
Equals: Disposable personal income	Millions of Fixed (2024) Dollars	+101.413	+203.446	+212.042	+224.263	+231.361	+235.993	+239.093	+241.781	+244.851

Comparison Type: Montana - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

MATS rulemaking impacts - Income Profile

		Year								
Category	Units	2036	2037	2038	2039	2040	2041	2042	2043	2044
Total Earnings by Place of Work	Millions of Fixed (2024) Dollars	+272.327	+271.092	+270.981	+271.757	+273.181	+275.060	+277.197	+279.431	+281.682
Total Wages and Salaries	Millions of Fixed (2024) Dollars	+190.889	+190.408	+190.565	+191.211	+192.201	+193.446	+194.828	+196.265	+197.713
Supplements to Wages and Salaries	Millions of Fixed (2024) Dollars	+58.478	+58.782	+59.223	+59.798	+60.475	+61.212	+61.988	+62.764	+63.523
Employer contributions for employee pens	Millions of Fixed (2024) Dollars	+37.316	+37.510	+37.791	+38.158	+38.590	+39.061	+39.555	+40.051	+40.535
Employer contributions for government so	Millions of Fixed (2024) Dollars	+21.162	+21.272	+21.432	+21.640	+21.885	+22.152	+22.432	+22.713	+22.988
Proprietors' income with inventory valuatio	Millions of Fixed (2024) Dollars	+22.961	+21.902	+21.193	+20.748	+20.505	+20.402	+20.381	+20.402	+20.445
Less: Contributions for Government Social Ins	Millions of Fixed (2024) Dollars	+39.746	+39.738	+39.834	+40.010	+40.241	+40.517	+40.814	+41.122	+41.431
Employee and Self-Employed Contributions	Millions of Fixed (2024) Dollars	+18.584	+18.466	+18.402	+18.370	+18.356	+18.365	+18.382	+18.408	+18.443
Employer contributions for government so	Millions of Fixed (2024) Dollars	+21.162	+21.272	+21.432	+21.640	+21.885	+22.152	+22.432	+22.713	+22.988
Plus: Adjustment for Residence	Millions of Fixed (2024) Dollars	-0.684	-0.663	-0.649	-0.640	-0.635	-0.633	-0.633	-0.634	-0.636
Gross Inflow	Millions of Fixed (2024) Dollars	-0.270	-0.268	-0.266	-0.266	-0.266	-0.268	-0.270	-0.272	-0.274
Gross Outflow	Millions of Fixed (2024) Dollars	+0.414	+0.395	+0.383	+0.374	+0.368	+0.365	+0.363	+0.362	+0.362
Equals: Net Earnings by Place of Residence	Millions of Fixed (2024) Dollars	+231.898	+230.692	+230.498	+231.108	+232.305	+233.911	+235.750	+237.675	+239.616
Plus: Property Income	Millions of Fixed (2024) Dollars	+33.745	+35.991	+38.206	+40.402	+42.562	+44.728	+46.858	+48.968	+51.047
Personal Dividend Income	Millions of Fixed (2024) Dollars	+14.688	+15.694	+16.690	+17.680	+18.658	+19.643	+20.614	+21.580	+22.536
Personal Interest Income	Millions of Fixed (2024) Dollars	+12.296	+13.073	+13.834	+14.583	+15.314	+16.042	+16.753	+17.452	+18.136
Rental Income of Persons	Millions of Fixed (2024) Dollars	+6.761	+7.224	+7.683	+8.139	+8.590	+9.043	+9.490	+9.935	+10.376
Plus: Personal Current Transfer Receipts	Millions of Fixed (2024) Dollars	+22.752	+26.127	+29.302	+32.326	+35.167	+37.867	+40.471	+42.956	+45.286
Equals: Personal Income	Millions of Fixed (2024) Dollars	+288.394	+292.810	+298.006	+303.836	+310.033	+316.507	+323.079	+329.599	+335.949
Less: Personal current taxes	Millions of Fixed (2024) Dollars	+39.991	+40.186	+40.522	+40.975	+41.504	+42.089	+42.706	+43.332	+43.948
Equals: Disposable personal income	Millions of Fixed (2024) Dollars	+248.403	+252.624	+257.483	+262.860	+268.530	+274.417	+280.373	+286.267	+292.001

MATS rulemaking impacts - Output

Industry	Units	Year 2027	2028	2029	2030	2031	2032	2033	2034
All Industries	**Millions of Fixed (2024) Dollars**	**+497.178**	**+1011.370**	**+1040.713**	**+1051.794**	**+1047.385**	**+1036.244**	**+1024.039**	**+1013.485**
Forestry and Logging; Fishing, hunting and trap	Millions of Fixed (2024) Dollars	+0.157	+0.286	+0.229	+0.165	+0.099	+0.039	-0.014	-0.057
Support activities for agriculture and forestry	Millions of Fixed (2024) Dollars	+0.010	+0.016	+0.009	+0.002	-0.005	-0.011	-0.016	-0.020
Oil and gas extraction	Millions of Fixed (2024) Dollars	+0.452	+0.764	+0.496	+0.244	+0.014	-0.174	-0.322	-0.428
Mining (except oil and gas)	Millions of Fixed (2024) Dollars	+129.533	+258.525	+257.920	+257.243	+256.558	+255.877	+255.350	+254.853
Support activities for mining	Millions of Fixed (2024) Dollars	+7.057	+14.260	+14.413	+14.554	+14.681	+14.811	+14.946	+15.090
Utilities	Millions of Fixed (2024) Dollars	+154.968	+310.943	+312.477	+314.395	+316.324	+318.305	+320.397	+322.509
Construction	Millions of Fixed (2024) Dollars	+43.723	+95.722	+107.506	+108.032	+101.700	+92.214	+82.016	+72.552
Wood product manufacturing	Millions of Fixed (2024) Dollars	+1.442	+3.035	+3.231	+3.121	+2.832	+2.479	+2.129	+1.819
Nonmetallic mineral product manufacturing	Millions of Fixed (2024) Dollars	+0.417	+0.869	+0.913	+0.884	+0.813	+0.726	+0.639	+0.562
Primary metal manufacturing	Millions of Fixed (2024) Dollars	+0.238	+0.477	+0.480	+0.471	+0.455	+0.444	+0.424	+0.410
Fabricated metal product manufacturing	Millions of Fixed (2024) Dollars	+0.730	+1.502	+1.561	+1.533	+1.452	+1.356	+1.251	+1.161
Machinery manufacturing	Millions of Fixed (2024) Dollars	+0.166	+0.338	+0.354	+0.349	+0.334	+0.319	+0.285	+0.257
Computer and electronic product manufacturin	Millions of Fixed (2024) Dollars	+0.084	+0.138	+0.071	-0.009	-0.091	-0.167	-0.229	-0.280
Electrical equipment, appliance, and component	Millions of Fixed (2024) Dollars	+0.001	+0.001	-0.002	-0.005	-0.008	-0.010	-0.013	-0.015
Motor vehicles, bodies and trailers, and parts m	Millions of Fixed (2024) Dollars	+0.344	+0.724	+0.792	+0.827	+0.839	+0.845	+0.838	+0.832
Other transportation equipment manufacturing	Millions of Fixed (2024) Dollars	+0.056	+0.116	+0.123	+0.125	+0.124	+0.122	+0.121	+0.120
Furniture and related product manufacturing	Millions of Fixed (2024) Dollars	+0.230	+0.463	+0.472	+0.464	+0.440	+0.412	+0.387	+0.367
Miscellaneous manufacturing	Millions of Fixed (2024) Dollars	+0.128	+0.238	+0.207	+0.173	+0.136	+0.102	+0.074	+0.052
Food manufacturing	Millions of Fixed (2024) Dollars	+0.871	+1.774	+1.859	+1.915	+1.927	+1.927	+1.908	+1.897
Beverage and tobacco manufacturing	Millions of Fixed (2024) Dollars	+0.460	+0.955	+1.054	+1.134	+1.182	+1.210	+1.224	+1.234
Textile mills and textile product mills	Millions of Fixed (2024) Dollars	+0.038	+0.071	+0.066	+0.057	+0.047	+0.038	+0.029	+0.022
Apparel, leather and allied product manufacturi	Millions of Fixed (2024) Dollars	+0.013	+0.020	+0.008	-0.003	-0.014	-0.023	-0.029	-0.033
Paper manufacturing	Millions of Fixed (2024) Dollars	+0.005	+0.009	+0.009	+0.009	+0.009	+0.008	+0.008	+0.008
Printing and related support activities	Millions of Fixed (2024) Dollars	+0.064	+0.123	+0.114	+0.102	+0.088	+0.076	+0.065	+0.057
Petroleum and coal products manufacturing	Millions of Fixed (2024) Dollars	+9.783	+18.595	+16.974	+15.248	+13.559	+12.059	+10.849	+9.953
Chemical manufacturing	Millions of Fixed (2024) Dollars	+0.135	+0.249	+0.216	+0.184	+0.152	+0.125	+0.101	+0.083
Plastics and rubber products manufacturing	Millions of Fixed (2024) Dollars	+0.400	+0.807	+0.826	+0.818	+0.792	+0.763	+0.730	+0.704
Wholesale trade	Millions of Fixed (2024) Dollars	+12.679	+25.495	+25.898	+25.800	+25.205	+24.489	+23.888	+23.466
Retail trade	Millions of Fixed (2024) Dollars	+15.141	+31.247	+33.213	+34.606	+35.147	+35.275	+35.370	+35.508

MATS rulemaking impacts - Output

Industry	Units	Year 2035	2036	2037	2038	2039	2040	2041	2042
All Industries	**Millions of Fixed (2024) Dollars**	**+1006.302**	**+1002.551**	**+1002.198**	**+1004.923**	**+1010.001**	**+1016.793**	**+1024.776**	**+1033.363**
Forestry and Logging; Fishing, hunting and trap	Millions of Fixed (2024) Dollars	-0.088	-0.109	-0.122	-0.129	-0.132	-0.133	-0.131	-0.129
Support activities for agriculture and forestry	Millions of Fixed (2024) Dollars	-0.023	-0.025	-0.026	-0.027	-0.027	-0.027	-0.026	-0.026
Oil and gas extraction	Millions of Fixed (2024) Dollars	-0.508	-0.568	-0.612	-0.642	-0.662	-0.674	-0.681	-0.684
Mining (except oil and gas)	Millions of Fixed (2024) Dollars	+254.386	+253.951	+253.549	+253.155	+252.771	+252.388	+252.004	+251.618
Support activities for mining	Millions of Fixed (2024) Dollars	+15.244	+15.406	+15.573	+15.751	+15.938	+16.133	+16.337	+16.548
Utilities	Millions of Fixed (2024) Dollars	+324.685	+326.866	+329.029	+331.270	+333.560	+335.919	+338.348	+340.829
Construction	Millions of Fixed (2024) Dollars	+64.649	+58.490	+54.018	+51.006	+49.134	+48.083	+47.595	+47.431
Wood product manufacturing	Millions of Fixed (2024) Dollars	+1.568	+1.378	+1.245	+1.159	+1.109	+1.084	+1.076	+1.078
Nonmetallic mineral product manufacturing	Millions of Fixed (2024) Dollars	+0.500	+0.452	+0.418	+0.395	+0.381	+0.374	+0.370	+0.369
Primary metal manufacturing	Millions of Fixed (2024) Dollars	+0.400	+0.393	+0.390	+0.388	+0.389	+0.390	+0.392	+0.394
Fabricated metal product manufacturing	Millions of Fixed (2024) Dollars	+1.089	+1.035	+0.998	+0.975	+0.963	+0.958	+0.958	+0.961
Machinery manufacturing	Millions of Fixed (2024) Dollars	+0.235	+0.217	+0.203	+0.192	+0.184	+0.183	+0.184	+0.186
Computer and electronic product manufacturin	Millions of Fixed (2024) Dollars	-0.320	-0.351	-0.374	-0.391	-0.404	-0.414	-0.421	-0.428
Electrical equipment, appliance, and component	Millions of Fixed (2024) Dollars	-0.016	-0.017	-0.018	-0.019	-0.019	-0.020	-0.020	-0.020
Motor vehicles, bodies and trailers, and parts n	Millions of Fixed (2024) Dollars	+0.828	+0.828	+0.831	+0.838	+0.847	+0.857	+0.869	+0.881
Other transportation equipment manufacturing	Millions of Fixed (2024) Dollars	+0.121	+0.121	+0.123	+0.125	+0.128	+0.131	+0.135	+0.139
Furniture and related product manufacturing	Millions of Fixed (2024) Dollars	+0.352	+0.343	+0.339	+0.338	+0.341	+0.346	+0.353	+0.360
Miscellaneous manufacturing	Millions of Fixed (2024) Dollars	+0.036	+0.024	+0.017	+0.013	+0.012	+0.013	+0.015	+0.017
Food manufacturing	Millions of Fixed (2024) Dollars	+1.896	+1.903	+1.919	+1.939	+1.963	+1.988	+2.013	+2.034
Beverage and tobacco manufacturing	Millions of Fixed (2024) Dollars	+1.241	+1.248	+1.256	+1.266	+1.275	+1.283	+1.291	+1.298
Textile mills and textile product mills	Millions of Fixed (2024) Dollars	+0.017	+0.014	+0.012	+0.011	+0.010	+0.010	+0.011	+0.011
Apparel, leather and allied product manufacturi	Millions of Fixed (2024) Dollars	-0.036	-0.037	-0.037	-0.036	-0.034	-0.032	-0.030	-0.027
Paper manufacturing	Millions of Fixed (2024) Dollars	+0.007	+0.007	+0.007	+0.007	+0.007	+0.007	+0.007	+0.007
Printing and related support activities	Millions of Fixed (2024) Dollars	+0.051	+0.046	+0.044	+0.042	+0.041	+0.041	+0.041	+0.041
Petroleum and coal products manufacturing	Millions of Fixed (2024) Dollars	+9.282	+8.781	+8.415	+8.158	+7.976	+7.843	+7.746	+7.667
Chemical manufacturing	Millions of Fixed (2024) Dollars	+0.070	+0.060	+0.054	+0.049	+0.047	+0.045	+0.044	+0.044
Plastics and rubber products manufacturing	Millions of Fixed (2024) Dollars	+0.683	+0.668	+0.658	+0.653	+0.650	+0.649	+0.650	+0.651
Wholesale trade	Millions of Fixed (2024) Dollars	+23.218	+23.124	+23.183	+23.382	+23.674	+24.028	+24.431	+24.856
Retail trade	Millions of Fixed (2024) Dollars	+35.800	+36.225	+36.806	+37.509	+38.333	+39.251	+40.237	+41.253

MATS rulemaking impacts - By Age

		Year								
Age	Units	2027	2028	2029	2030	2031	2032	2033	2034	2035
All Ages (0-100)	**Individuals**	**+477.798**	**+1304.930**	**+1939.678**	**+2440.929**	**+2825.319**	**+3117.124**	**+3338.788**	**+3510.243**	**+3647.479**
Ages 0-4	Individuals	+48.782	+132.680	+195.930	+244.700	+281.046	+303.413	+315.601	+324.460	+330.517
Ages 5-9	Individuals	+37.323	+102.959	+155.311	+198.400	+232.772	+263.912	+291.507	+311.761	+326.801
Ages 10-14	Individuals	+29.739	+82.160	+124.247	+159.317	+188.144	+211.970	+232.086	+249.665	+265.438
Ages 15-19	Individuals	+31.186	+80.948	+112.861	+135.841	+154.243	+170.951	+186.234	+200.032	+213.026
Ages 20-24	Individuals	+75.320	+197.616	+273.714	+313.070	+320.743	+306.793	+283.134	+258.859	+238.780
Ages 25-29	Individuals	+68.886	+190.243	+286.964	+365.786	+426.212	+467.322	+486.890	+484.519	+462.466
Ages 30-34	Individuals	+50.312	+140.072	+214.357	+278.601	+333.557	+380.159	+419.903	+454.296	+484.061
Ages 35-39	Individuals	+37.475	+103.620	+157.157	+202.680	+241.445	+275.204	+305.804	+334.896	+363.577
Ages 40-44	Individuals	+32.781	+89.958	+134.483	+169.886	+197.289	+218.856	+237.068	+253.975	+270.779
Ages 45-49	Individuals	+23.849	+66.353	+101.443	+131.716	+157.580	+179.601	+197.896	+212.720	+224.763
Ages 50-54	Individuals	+17.691	+49.024	+74.501	+96.083	+114.281	+129.943	+144.031	+157.396	+170.555
Ages 55-59	Individuals	+13.068	+35.960	+54.267	+69.819	+83.131	+94.780	+105.134	+114.568	+123.502
Ages 60-64	Individuals	+11.388	+31.537	+47.603	+60.392	+69.926	+76.759	+82.038	+86.863	+91.823
Ages 65-69	Individuals	+0.000	+1.800	+6.840	+14.637	+24.950	+37.460	+49.785	+59.870	+67.794
Ages 70-74	Individuals	+0.000	+0.000	+0.000	+0.000	+0.000	+0.000	+1.677	+6.363	+13.595
Ages 75-79	Individuals	+0.000	+0.000	+0.000	+0.000	+0.000	+0.000	+0.000	+0.000	0.000
Ages 80-84	Individuals	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ages 85+	Individuals	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Category: Montana - Race: Population - Gender: All Races - Comparison Type: Total - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

MATS rulemaking impacts - By Age

Age	Units	2036	2037	2038	2039	2040	2041	2042	2043	2044
		Year								
All Ages (0-100)	**Individuals**	**+3761.717**	**+3860.652**	**+3949.665**	**+4031.275**	**+4106.385**	**+4175.468**	**+4238.252**	**+4293.884**	**+4341.941**
Ages 0-4	Individuals	+334.326	+336.155	+336.132	+334.221	+330.291	+324.305	+316.250	+306.210	+294.485
Ages 5-9	Individuals	+338.182	+342.842	+343.019	+343.982	+344.892	+345.324	+344.816	+342.919	+339.298
Ages 10-14	Individuals	+279.579	+296.349	+314.185	+328.019	+338.870	+347.500	+350.259	+348.914	+348.488
Ages 15-19	Individuals	+225.572	+237.876	+250.191	+262.640	+275.049	+286.966	+302.168	+318.711	+331.349
Ages 20-24	Individuals	+225.872	+220.707	+221.341	+225.569	+232.288	+240.612	+249.845	+259.546	+269.490
Ages 25-29	Individuals	+424.819	+378.817	+333.478	+294.996	+265.674	+246.704	+237.312	+234.520	+235.591
Ages 30-34	Individuals	+508.109	+523.400	+525.479	+511.685	+482.306	+439.961	+390.824	+343.025	+302.288
Ages 35-39	Individuals	+392.130	+419.943	+446.903	+472.853	+497.101	+517.533	+530.351	+530.522	+515.074
Ages 40-44	Individuals	+288.286	+306.933	+327.244	+349.527	+373.706	+399.251	+424.931	+450.148	+474.507
Ages 45-49	Individuals	+234.845	+244.086	+253.908	+265.253	+278.391	+293.433	+310.336	+329.216	+350.165
Ages 50-54	Individuals	+183.693	+196.633	+208.718	+219.434	+228.779	+237.077	+245.085	+253.883	+264.265
Ages 55-59	Individuals	+132.280	+141.190	+150.627	+160.849	+171.876	+183.531	+195.372	+206.559	+216.472
Ages 60-64	Individuals	+97.248	+103.240	+109.678	+116.454	+123.570	+131.062	+138.996	+147.583	+156.985
Ages 65-69	Individuals	+73.649	+77.834	+81.277	+84.836	+88.895	+93.651	+99.096	+105.045	+111.354
Ages 70-74	Individuals	+23.127	+34.648	+45.976	+55.245	+62.534	+67.933	+71.826	+75.057	+78.407
Ages 75-79	Individuals	0.000	0.000	+1.509	+5.712	+12.164	+20.624	+30.784	+40.748	+48.903
Ages 80-84	Individuals	0.000	0.000	0.000	0.000	0.000	0.000	0.000	+1.277	+4.819
Ages 85+	Individuals	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

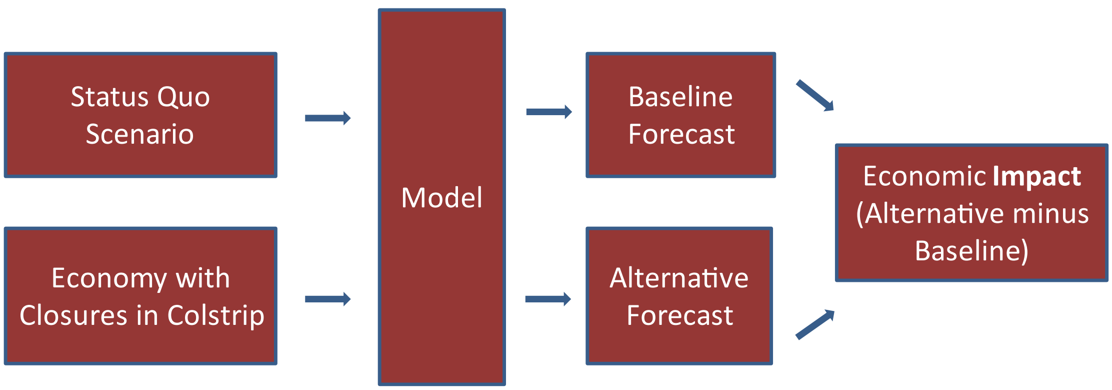
Category: Montana - Race: Population - Gender: All Races - Comparison Type: Total - Forecast: Differences - Comparison Forecast: MATS rulemaking impacts

Appendix B
Description of the REMI Model

The REMI Modeling Methodology

The basic approach of using the REMI model to produce the results for this study is illustrated in Figure B.3, below. The analysis started with a baseline projection for the Montana economy, where the Colstrip SES and Rosebud Mine are present. Next, the analysis employed the REMI model a second time, simulating an alternative scenario where the two facilities are closed and their associated economic activity are absent from the Montana economy.

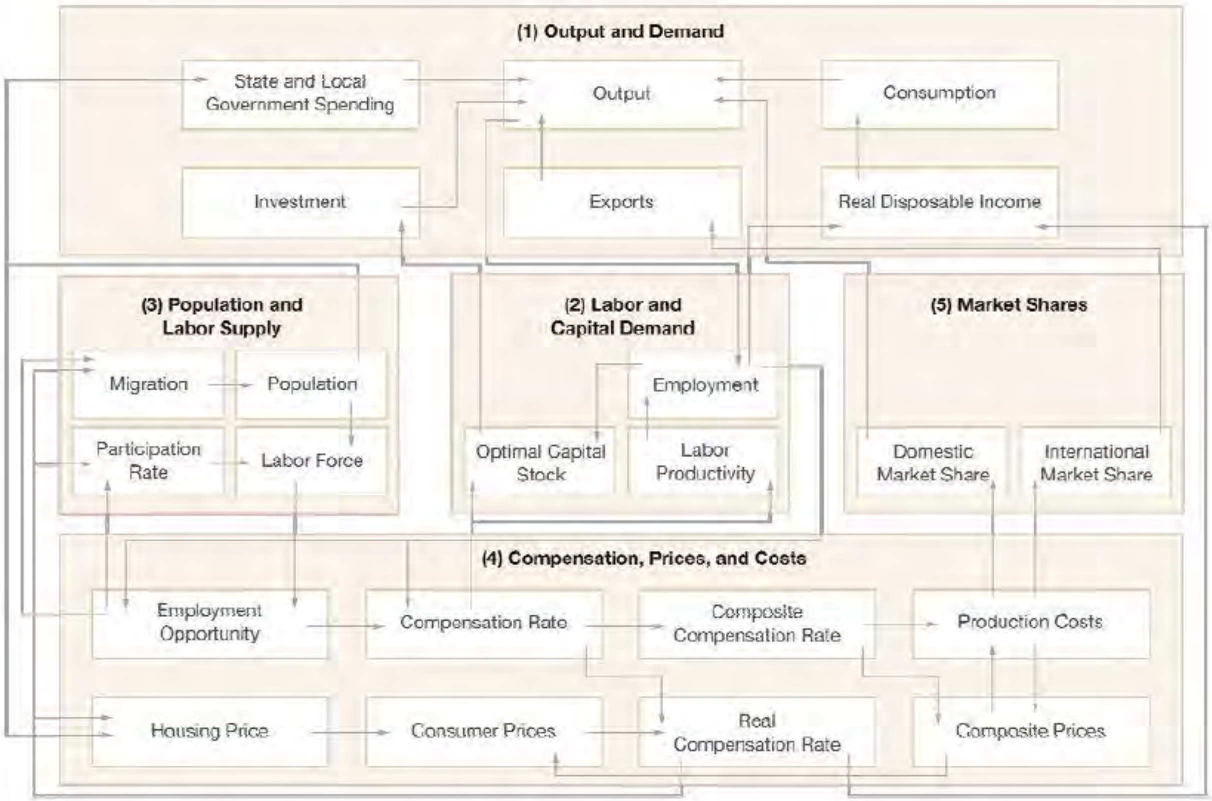
Figure B.3. Policy Analysis Using the REMI Model



The difference between the two economic projections represents the economic impact of MATS-induced rulemaking in Montana.

The REMI model utilizes historical data on production, prices, trade flows, migration, and technological advances to calibrate the relationship between five basic blocks of the state economy: 1) Output and Demand; 2) Labor and Capital Demand; 3) Population and Labor Supply; 4) Compensation, Prices and Costs; and 5) Market Shares. These linkages are shown in Figure B.4, below.

Figure B.4. Schematic Model of REMI Linkages



The differences in production, labor demand, and intermediate demand associated with the closure of the Colstrip SES and the Rosebud Mine impact these blocks, causing them to react to the changes and adjust to a new equilibrium. This new equilibrium constitutes the alternative scenario referred to above—the closure of the facilities.

The underlying philosophy of the REMI model is that regions throughout the country compete for investments, jobs, and people. When events occur in one region, they set off a chain reaction of events across the country that causes dollars to flow toward better investment and production opportunities, followed over time by workers and households toward better employment opportunities and higher wages.

The REMI model consists of an 70-sector input/output matrix that models the technological interdependence of production sectors of the economy, as well as extensive trade and capital flow data. Together, these components enable the estimates of the shares of each sector's demand that can be met by local production. Simplified illustrations of the schematic model in Figure B.4 are provided on the following pages, in figures B.3 through B.7.

Figure B.5. Output Linkages

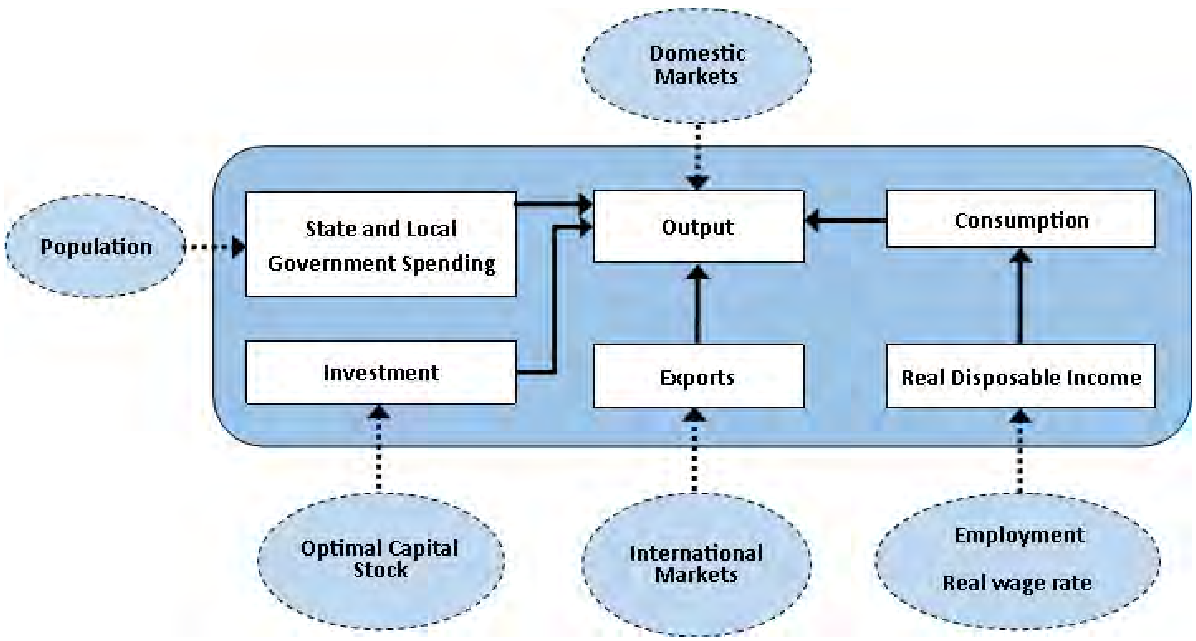


Figure B.6. Labor and Capital Demand Linkages

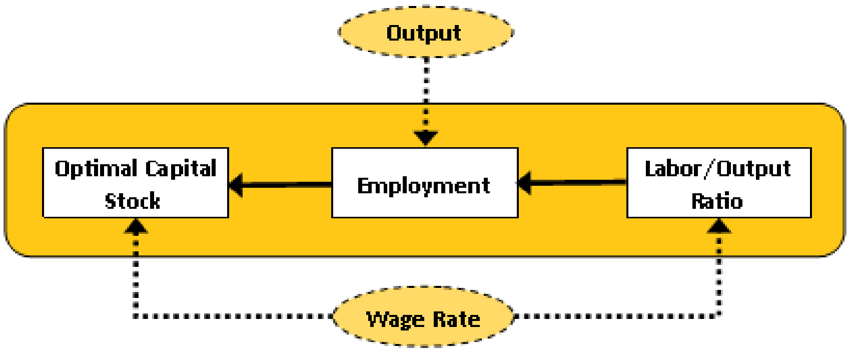


Figure B.7. Demographic Linkages

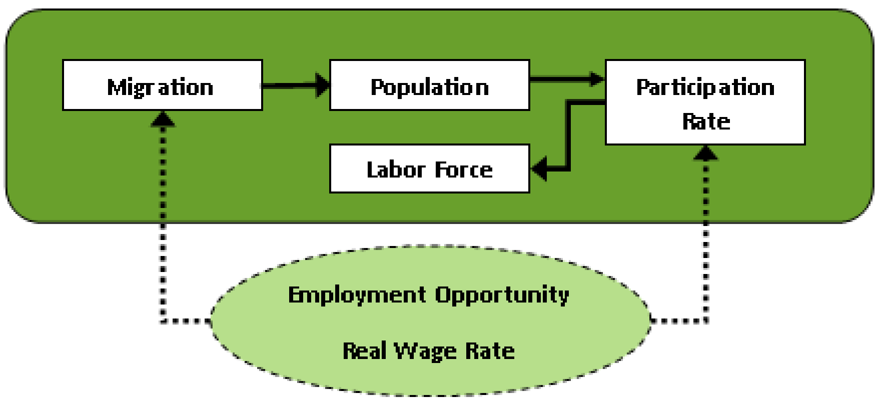


Figure B.8. Wages, Prices and Production Costs Linkages

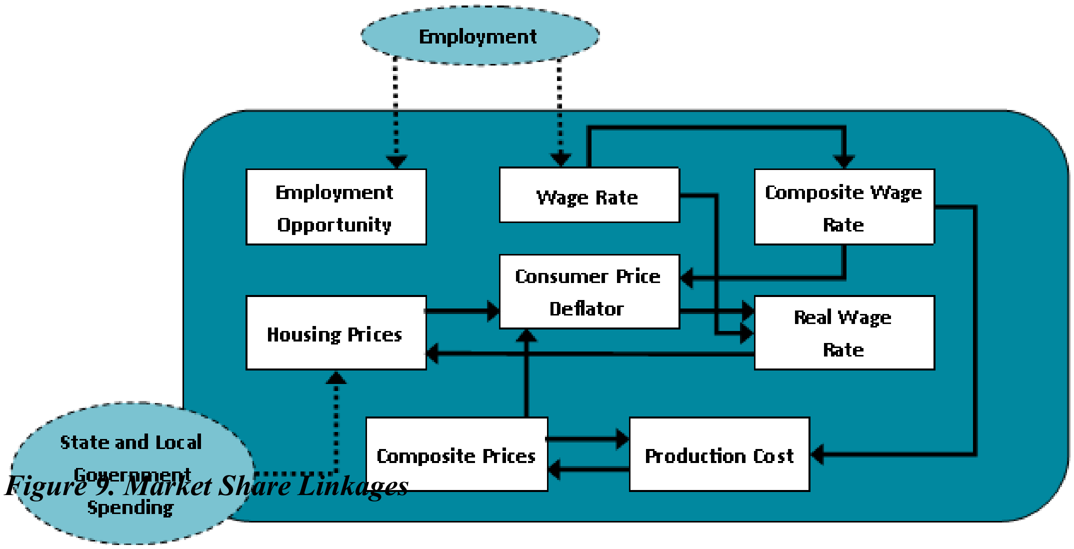
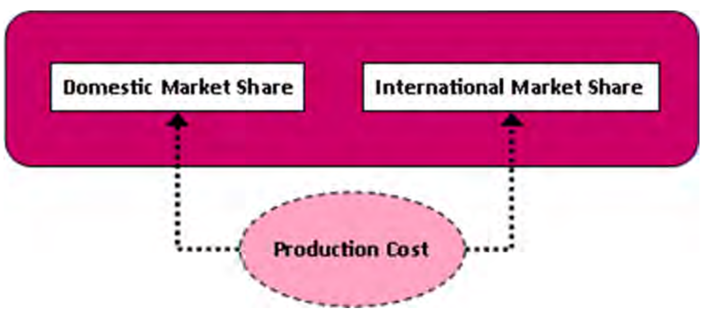


Figure 9. Market Share Linkages



As powerful and flexible as this tool is, the output it provides is only as good as the inputs provided. The majority of the work for this study was to carefully craft the inputs used to construct a scenario for the economy that faithfully represents all of the events, income flows, and the direct and indirect activity that would occur in the event that the Colstrip SES and the Rosebud Mine were closed in mid-2027.

Declaration of John D. Hines
In Support of Petitioners' Motion to Stay Final Rule

I, John D. Hines, having been duly sworn and upon my oath, hereby declare and state as follows:

1. My name is John D. Hines and I am NorthWestern Corporation d/b/a NorthWestern Energy's ("NorthWestern") Vice President – Supply, Environment and Montana Government Affairs. I have been the executive responsible for NorthWestern's energy supply since 2011 and have worked in the energy industry since 1989.

2. I am over the age of 18 and I make this Declaration based on my personal knowledge.

3. As NorthWestern's Vice President – Supply, Environment and Montana Government Affairs, I am responsible for ensuring that NorthWestern has the power generation resources required to meet the electrical power needs of its customers reliably, affordably, and safely in a sustainable manner consistent with all applicable laws and regulations. As part of my responsibilities, I oversee NorthWestern's resource planning function and the development of NorthWestern's Electric Supply Resource Procurement Plans as required by Montana law and operations of our generation fleet and a marketing function that buys and sells electricity depending on the status of the portfolio. I am also responsible for lands management, permitting, and environmental compliance, as well as NorthWestern's governmental affairs in Montana.

4. On June 23, 2023, NorthWestern provided comments to the United States Environmental Protection Agency ("EPA") on the Proposal on National Emissions Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, published in the *Federal Register* on April 24, 2023, at 88 Fed. Reg. 24,854 ("Proposed MATS2 Rule" (referred to as "MATS2" because it is a

revision to the original MATS Rule promulgated in 2012). I assisted in the development of these comments ("NorthWestern MATS2 Comments")). A copy of the NorthWestern MATS2 Comments is attached as Exhibit A.

5. On August 8, 2023, NorthWestern also provided comments on the 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. The proposal was published in the *Federal Register* at 88 Fed. Reg. 33,240 (May 23, 2023). I assisted in the development of these comments ("NorthWestern GHG Rule Comments"). A copy of the NorthWestern GHG Rule Comments is attached as Exhibit B (omitting exhibits that are duplicative of the exhibits to the NorthWestern MATS2 Comments).

6. On December 20, 2023, NorthWestern also provided comments on the Initial Regulatory Flexibility Analysis ("IRFA") on reliability concerns arising from EPA's proposed 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 ("EGUs"); and Repeal of the Affordable Clean Energy Rule. The rule proposal was published in the *Federal Register* at 88 Fed. Reg. 33,240 (May 23, 2023) ("Proposed Rule"), and the solicitation for supplemental comments on the IRFA was published in the *Federal Register* at 88 Fed. Reg. 80,662 (Nov. 20, 2023) ("NorthWestern Supplemental Reliability Comments"). I assisted in the development of the NorthWestern Supplemental Reliability Comments, and I also provided a declaration in support of the comments. A copy of the NorthWestern Supplemental Reliability Comments is attached as Exhibit C (again omitting exhibits duplicative of those in Exhibits A and B).

7. For this Declaration, I reiterate the primary points from the earlier comments and provide additional updated facts. I have also evaluated the changes from the Proposed MATS2 Rule to the final rule announced on April 25, 2024 and published in the Federal Register on May 7, 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. 38,508 (May 7, 2024) ("MATS2 Rule"). The MATS2 Rule is a complex regulation that NorthWestern continues to evaluate.

8. Nevertheless, there are certain conclusions that can be drawn at present regarding the impacts of the MATS2 Rule on NorthWestern, its customers, and the rate paying citizens of Montana. My comments here focus principally on the implications of the MATS2 Rule on the future of NorthWestern's ownership share in the Colstrip Steam Electric Station, located in Colstrip, Montana ("Colstrip") and thus the potential effects on our portfolio. Presently NorthWestern owns 222 MW and starting in 2026 it will acquire an additional 222 MW for a total of 444 MW of capacity in Colstrip Units 3 & 4. Colstrip Units 3 & 4 are coal-fired electric generating units ("EGUs"), and other than small waste-coal units not relevant to the MATS2 Rule, the only coal-fired EGUs in NorthWestern's Montana electric generation portfolio.

9. In this Declaration, I make the following points:

a. NorthWestern has analyzed various potential closure dates for Colstrip through its public Integrated Resource Planning ("IRP") process. Prior to the finalization of the GHG Rule and MATS2 Rule, NorthWestern had planned for reliance on Colstrip through 2042. Finalization of the GHG and MATS2 Rules creates two additional closure scenarios: July 8, 2027 (when compliance with the MATS2 Rule is required, unless the State grants a one year extension), and January 1, 2032 (when, under the GHG Rule, existing coal-fired EGUs must close if they have not installed carbon dioxide capture, utilization, and storage ("CCUS")).

b. Installation of additional controls at Colstrip to meet the 0.010 lb/MMbtu filtered particulate matter ("fPM") standard in the MATS2 Rule would require extremely large capital investments and annual operating costs, neither of which are cost-effective under the 2032 Colstrip closure scenario. The additional costs associated with the GHG Rule are so large that NorthWestern cannot envision operating Colstrip beyond January 1, 2032, in the event the GHG Rule is not vacated.

c. Because the additional MATS2 controls are substantial and not cost-effective, it is not clear that NorthWestern can obtain rate recovery approval from the Montana Public Service Commission ("MPSC") for the costs.

d. If NorthWestern cannot obtain rate recovery, NorthWestern will directly experience material irreparable harm.

e. Even if NorthWestern can obtain rate recovery, the costs will result in material increases in electricity rates for Montana ratepayers, to no environmental or incremental power benefit.

f. Because of these uncertainties and risks, NorthWestern is seeking advance rate recovery approval for MATS2 Rule compliance costs from the MPSC, but NorthWestern will not know the outcome of that proceeding before binding commitments must be made to meet the applicable compliance deadline.

g. NorthWestern cannot develop replacement electrical generation or transmission capacity for Colstrip under either the 2027 or 2032 closure scenarios.

h. Closure of Colstrip under either the 2027 or 2032 closure scenarios will materially impair Montana electrical grid reliability and our ability to reliably serve our customers.

i. EPA has not articulated an identifiable path to extend Colstrip's life beyond January 1, 2032. EPA has misinterpreted the various legal and administrative authorities it claims could provide relief from the MATS and/or GHG Rules, absent a stay of both Rules.

These points are discussed in further detail in the remainder of this Declaration.

Colstrip lifespan and closure scenario in the absence of the MATS2 Rule

10. Colstrip Units 3 & 4 have been in operation since 1984 and 1986, respectively. Although the Units have been well maintained and are capable of years of continued operations, they are in the latter stages of their operational life, which factors into the economic justification for major capital investments. NorthWestern in its current Montana resource planning has forecasted Units 3 & 4 would cease operation in 2042.

11. This forecast was significantly influenced by several factors. First, replacement capacity has long planning, permitting, and construction times. Second, there are promising developing alternatives to baseload fossil fuel energy sources, but these require additional time to mature. Third, and critically in relation to the MATS2 Rule, EPA found as recently as 2020 that further controls on Hazardous Air Pollutants were not warranted to protect human health, and there had been no developments that would warrant further controls. Consequently, NorthWestern could reasonably focus on improving and integrating its renewables portfolio and investing in similar infrastructure needs without the immediate need to replace Colstrip's capacity or budget for major additional pollution controls.

12. In fact, in early 2023 (prior to announcement of the Proposed GHG and MATS2 Rules), NorthWestern and Avista Corporation ("Avista") entered into an agreement whereby NorthWestern will acquire Avista's 222 MW combined shares of Colstrip Units 3 & 4 ("Avista Agreement"). NorthWestern determined that acquisition of additional Colstrip capacity was needed to address ongoing reliability and supply needs, for the reasons detailed later in this Declaration.

Extent of compliance Investments and cost-effectiveness of the MATS 2 Rule

13. In its NorthWestern MATS2 Comments, NorthWestern joined Talen Montana, LLC's ("Talen") contemporaneous comments that compliance with the 0.010 lb/MMbtu standard would require the installation of a new baghouse, in the most likely configuration (Reheat Fabric Filter) at an estimated cost of $350 million in capital and $15 million in annual operational/maintenance costs, annualizing to $57 million per year under an assumed 15 year operational life. This contrasts with EPA's original estimate of $38 million/year. I have seen no meaningful rebuttal of Talen's cost estimates from EPA.

14. NorthWestern and Talen further commented that the combination of the MATS2 Rule and GHG Rule would, given today's technology, force early closure of Colstrip. Assuming that Colstrip obtains the one-year compliance extension allowed for in the final MATS2 Rule, which can only be granted if reasonable progress is being made on installing the emission controls, Colstrip would need to come into compliance by July 8, 2028. Further, under the final GHG Rule, Colstrip would need to come into compliance with the GHG Rule's CCUS requirements or close by December 31, 2031. Consequently, if Colstrip closes by December 31, 2031, then the costs of the MATS Rule would be amortized over less than 3.5 years, rather than the 15 assumed by EPA. Even accounting for the reduced years of operational and maintenance

expenses, annualized costs would soar to approximately $120 million under Talen's cost estimates.

15. NorthWestern cannot envision a scenario in which it could operate Colstrip beyond December 31, 2031, if the GHG Rule is not vacated. As stated in NorthWestern's GHG Rule Comments, CCUS is not sufficiently demonstrated to provide confidence that the required GHG control rates could be reliably achieved, and even if they were, the costs of compliance would be astronomical in relation to Colstrip's remaining useful life. In addition, even if NorthWestern were to propose implementing CCUS to extend the life of Colstrip beyond 2031, there is a high likelihood the MPSC would conclude the investment would be imprudent and deny cost recovery. For these reasons, in this Declaration I principally examine and contrast various MATS2 implementation scenarios through 2031.

16. Under the applicable Ownership and Operation Agreement for Colstrip Units 3 & 4 and the Avista Agreement, NorthWestern would bear 30% of the MATS2 compliance costs. Using Talen's cost estimates, this translates to $36 million in new annualized costs for NorthWestern alone for the short period the fPM controls would be in use.

17. As explained in Talen's comments on the MATS2 Rule, the MATS2 Rule would result in extraordinary costs per ton of $92,000/ton for fPM removal for a Reheat Fabric Filter operating from EPA's 0.0195 lb/MMbtu performance baseline. Per-ton compliance costs would more than double with a 2031 closure date. I further note that Montana has more stringent mercury emission standards than the MATS2 Rule, and Colstrip already complies with the Montana mercury standard. Consequently, the MATS2 Rule will provide no material benefit with regard to Colstrip's mercury emissions.

The MATS2 Rule will materially increase electricity-delivery costs in Montana, and it is uncertain whether those will be recoverable in electrical rates

18. As a regulated utility, NorthWestern can only charge electricity rates to customers approved by the MPSC, after the completion of statutory and administrative processes. Mont. Code Ann. § 69-3-101; *see also id.* § 69-3-302; Admin. R. Mont. 38.5.101, *et seq.* The MPSC supervises, regulates, and controls public utilities, including NorthWestern. Mont. Code Ann § 69-3-102.

19. The processing of a proposal to increase electricity rates is referred to as a "rate case" or "rate review." Under general utility regulation law and ratemaking principles, any utility capital investment or facility must be used and useful to the rate paying public before a regulatory commission may permit a utility to recover costs through customer rates for the investment. Further, any cost or investment must be determined by the regulatory authority to be prudently incurred before cost recovery is authorized. With some limited exceptions for common recurring costs, such as supply costs or property tax adjustments, NorthWestern must apply to the MPSC in a formal rate review to recover any costs already incurred. NorthWestern often experiences what is known as "regulatory lag," where the company cannot timely recover costs for important investments made which serve customers and help provide safe, reliable, and affordable energy. This delay happens between rate cases, which are expensive and extremely resource consumptive to undertake. In recent years, NorthWestern has experienced harm from regulatory lag and has argued and demonstrated to the MPSC that the company's creditworthiness is impacted by delays in cost recovery.

20. NorthWestern began scoping its last rate case in 2021 and filed the case in in August 2022, based on investments made up through 2021. *See* MPSC Docket No. 2022.07.078 ("2022 Rate Case"). There were more than 600 docket entries in the administrative record over the course of the 2022 Rate Case, including thousands of discovery requests, a deposition, a six-

day-long evidentiary hearing, motions for summary judgment, an on-site audit, motions for reconsideration after the MPSC's decision, and additional proceedings. The Commission issued its order on reconsideration in the 2022 Rate Case in early 2024.

21. At the conclusion of the 2022 Rate Case, the MPSC approved a 28% increase in residential electricity rates. NorthWestern is relatively small utility, with a Montana electric customer base of approximately 400,000. Tens of millions of dollars in new capital and operating costs has a material effect on Montana electricity rates. A substantial annualized increase in compliance costs attributed to the MATS2 Rule would be presented to the MPSC to be added to rates. Importantly, to the extent that NorthWestern needs to purchase additional electricity from other Colstrip owners during periods of high demand, the MATS2 Rule costs would be reflected in their market rates as well.

22. Even assuming NorthWestern would close Colstrip by December 31, 2031 to avoid the exorbitant costs associated with the GHG Rule, NorthWestern is facing other substantial electricity-related costs through 2031. These include continued investments in much-needed transmission to accommodate increased renewable generation, wildfire mitigation initiatives, and rate recovery for other ongoing capital and operational projects. During this period, it is reasonably foreseeable that other rate increases will be needed to cover other electricity-related costs. In that context, MATS2 Rule implementation costs would be punitive to ratepayers, especially those of lesser means.

23. Conversely, if the MPSC denies rate recovery for MATS2 Rule compliance costs, $120+ million in non-recoverable costs, with the capital component incurred over the next four years, would have a material impact on NorthWestern's financial viability.

24. NorthWestern is commencing a new rate case in July, 2024. Because of the high consequences of the MATS2 Rule, NorthWestern will be asking the MPSC for an accounting mechanism to address MATS2 Rule compliance costs. Given required statutory and administrative processes and prior experience, it is not plausible that this proceeding will be completed prior to the date by which binding commitments are necessary to install the required controls in time to meet the 2027 or 2028 compliance deadlines. The decision points and timelines associated with fPM control contracting and installation are discussed in more detail in the declaration of Dale Lebsack. NorthWestern and its rate paying customers therefore face financially significant uncertainty no matter how the MPSC ultimately rules. If the MPSC allows rate recovery, then the rate paying public will face substantial electric rate increases. If the MPSC does not, then NorthWestern could be financially devastated. And NorthWestern cannot know the answer before the investment decisions must be made.

Electric grid reliability consequences of closure of Colstrip by the end of 2031 or earlier

25. One option to avoid the preceding conundrum would be to simply close Colstrip by the MATS2 Rule July 2027 compliance date. But closure of Colstrip prior to the mid-2030s, and especially by mid-2027, would create other types of potentially catastrophic and irreparable risks and harms.

26. NorthWestern addressed the electrical grid reliability implications of early closure of Colstrip in its NorthWestern MATS2 Comments, its NorthWestern GHG Rule Comments, and its NorthWestern Supplemental Reliability Comments.

27. In simplest form, when Colstrip is closed its generating capacity must be replaced. Capacity can be replaced in one of two principal ways: (1) new generation facilities can be built, or (2) electricity can be purchased from third-parties in the electricity market. Existing Montana

sources of market electricity purchases are either fully utilized, or equally affected by the MATS2 Rule (in the case of the shares of Colstrip Units 3 & 4 that are not owned by NorthWestern). The following paragraphs discuss NorthWestern's portfolio and its ability, or the lack thereof, to replace Colstrip's capacity with new generation or increased transmission from other sources.

28. NorthWestern and its South Dakota affiliate supply electrical energy and capacity to customers in Montana, including Yellowstone National Park and South Dakota. This Declaration focuses on Montana. As explained in the accompanying prior Declaration of Michael Cashell, NorthWestern's Vice President – Transmission (the content of which was included in the NorthWestern MATS2 Comments and submitted again in declaration form as Exhibit B to the NorthWestern Supplemental Reliability Comments), generation sources in Montana and the Dakotas are located in different Interconnection Regions, and electricity cannot readily be transmitted between the two Regions. NorthWestern provides electricity to customers in its Montana service area and also serves as the "Balancing Authority" in that part of Montana, which means that NorthWestern is responsible for ensuring that the supply of and demand for electricity within its Balancing Authority Area are constantly in equilibrium or "balanced."[1]

29. The MPSC has set forth the following objectives that Montana utilities should meet: (a) reliability; (b) affordability; (c) environmental responsibility; (d) optimality; and (e) transparency.

[1] In its South Dakota service area, NorthWestern participates in the Southwest Power Pool ("SPP"), which is a Regional Transmission Organization serving as a single Balancing Authority for interconnected electric utilities in 14 states. In 2015, NorthWestern ceded functional control of its South Dakota transmission facilities, and SPP is now responsible for operating the grid.

30. NorthWestern thus has legal obligations to reliably and affordably supply electricity to our customers in Montana and to do so cost-effectively while seeking to reduce adverse environmental impacts. In addition to those legal obligations, NorthWestern recognizes that as a practical matter its customers count on NorthWestern to provide the cost effective electricity used to power their homes and businesses and the critical infrastructure upon which they rely.

31. Under Montana law, NorthWestern, as a regulated public utility, is required to prepare and file a plan every three years for meeting the requirements of its customers in the most cost-effective manner consistent with its obligation to serve under the law. Mont. Code Ann. § 69-3-1204(1)(a).

32. The plan must include:

a. an evaluation of the full range of cost-effective means for the public utility to meet the service requirements of its Montana customers, including conservation or similar improvements in the efficiency by which services are used and including demand-side management programs in accordance with 69-3-1209;

b. an annual electric demand and energy forecast developed pursuant to commission rules that includes energy and demand forecasts for each year within the planning period and historical data, as required by commission rule;

c. assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to commission rules;

d. an assessment of the need for additional resources and the utility's plan for acquiring resources;

e. the proposed process the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive solicitation process in accordance with 69-3-1207; and

f. descriptions of at least two alternate scenarios that can be used to represent the costs and benefits from increasing amounts of renewable energy resources and demand-side management programs, based on rules developed by the commission.

33. Planning for reliable service requires NorthWestern to ensure that it has enough electricity generation resources to meet its customer demands every hour of the year, even with changing weather, generation output and demands. As a matter of physics, for the electric grid to operate reliably, the amount of energy generated ("generation") and the consumption of that energy ("load") must be equal or in balance. Generation and load must be in balance year-to-year, month-to-month, day-to-day, hour-by-hour, and minute-by minute for the electric grid to remain stable. Because of the long lead times needed to build or acquire new electrical generation or transmission assets or negotiate power purchase contracts, NorthWestern, like other electric utilities, makes plans for our supply of electricity years in advance. This long-term IRP is also required by law. In Montana, NorthWestern prepares formal, written plans that are filed with the MPSC. *See* NorthWestern MATS2 Comments, Exhibit D (NorthWestern May 2023 Integrated Resource Plan).

34. NorthWestern began to serve customers in Montana when it purchased transmission and distribution assets of the former Montana Power Company in 2002. Initially, NorthWestern did not own any generation assets to serve Montana customers. This situation was not ideal and was risky to customers as it required NorthWestern to purchase from the market all

the electricity needed to serve customers. These purchases were and continue to be from a market that reflects growing risk to customers and that has increasingly volatile pricing and potential supply shortages. These purchases also rely upon adequate transmission to move the electricity from the place of purchase to NorthWestern's transmission and distribution systems. Availability of such transmission presents yet another risk to greater reliance on market purchases.

35. Since 2002, NorthWestern has acquired various types of electricity supply resources, including its interests in Colstrip. Notably, in 2014 NorthWestern purchased a portfolio of hydroelectric facilities in Montana. NorthWestern has also made significant investments in wind power. NorthWestern has more wind owned and under contract than its existing share of generation from Colstrip and the share it is contracted to acquire from Avista. NorthWestern currently owns approximately 882 MW of generation capacity, has under construction or agreements in process for another 392 MW, and has long-term contracts for another 764 MW.

36. NorthWestern's current generation portfolio is a diverse and balanced mix of resources necessary to be reliable, the majority of which are renewable. The portfolio includes 497-MW of hydroelectric maximum delivered capacity, 455-MW of maximum delivered wind capacity, 222-MW of coal capacity at Colstrip, 202-MW of natural gas capacity, 92.5-MW of waste coal capacity (which under PURPA we are required to purchase), and 177-MW of solar capacity. The Company also has market capacity contracts for 410 MWs which have significant price or market exposure. In summary, NorthWestern's current portfolio has 202 MW of natural gas capacity, 315 MW of coal and waste coal based capacity, and 1,128 MW of renewable fueled

generation. As noted, under the Avista Agreement, NorthWestern is also scheduled to acquire ownership of another 222-MW of capacity at Colstrip commencing in 2026.

37. The table below lists NorthWestern's existing owned generation facilities and contracted generation resources along with some additional resources that the Company expects to bring online, including the Yellowstone County Generating Station ("YCGS") that is nearing full operational status and is expected to reliably serve NorthWestern's customers beginning July 1, 2024

MT Portfolio Resources
Hydro Generation - Online
Thompson Falls
Cochrane
Ryan
Rainbow
Holter
Morony
Black Eagle
Hauser
Mystic
Madison
Turnbull Hydro LLC
State of MT DNRC (Broadwater Dam)
Tiber Montana LLC
+ QF Hydro Resources
Thermal/Natural Gas Generation - Online
Basin Creek
DGGS 1 -3
Thermal/Natural Gas Generation – Under Construction
Yellowstone County Generating Station (Laurel)
Thermal/Coal Generation - Online
Colstrip 30% U4
Yellowstone Energy Limited Partnership (BGI) (QF)
Colstrip Energy Limited Partnership (QF)
Wind Generation - Online
Judith Gap Energy LLC
Spion Kop Wind
Two Dot Wind Farm
+QF Wind Resources

Solar Generation - Online	
+QF Solar Resources	
Short Term Contracts - Max	
Powerex (3 yr) Contingency Reserves (60 MW) - expires 12/31/2024	
Powerex (5 yr) (100 MW) - expires 12/31/2027	
Heartland (10 yr) - (150 MW) - expires 12/31/2032	

38. NorthWestern currently has over 200 percent more wind generation than Colstrip generation. In terms of generation asset nameplate capacity, its two largest, by far, are hydroelectric assets and the fleet of wind farms, both of which are carbon free. NorthWestern's portfolio of solar generating facilities has also been increasing in recent years. At the same time, it is critical to note the difference between "nameplate" and "accredited" capacity. Nameplate capacity refers to the maximum electrical generating output (in MW) that a generator can sustain over a specified period of time when not restricted by seasonal or other "deratings" (events that reduce effective output), as measured in accordance with the United States Department of Energy standards. In contrast, accredited capacity means the electrical rating given to generating equipment that meets the Utility's criteria for uniform rating of equipment. These criteria include but are not limited to reliability, availability, type of equipment and the degree of coordination between the Distributed Generation and the Utility. Wind and solar accredited capacities are much lower than their nameplate capacities, because of the seasonal and weather variability of those generation sources. Hydroelectric generation also has a gap between nameplate and accredited capacity, reflecting periods when generation is restricted by stream flows. All this is reflected in the table below:

MT Portfolio Resource	Nameplate Capacity (MW)	Accredited Capacity (MW)
Hydro Generation - Online		

Total	497	341
Thermal/Natural Gas Generation - Online		
Total	202	195
Thermal/Coal Generation - Online		
Total	315	309
Wind Generation - Online		
Total	455	109
Solar Generation - Online		
Total	177	11
Short Term Contracts - Max		
	410	410
Total	**2056**	**1375**

39. NorthWestern's proportion of generation resources that are renewable compares highly favorable to other utilities. In 2021, 56% of NorthWestern's electric generation was from carbon-free resources, which compares to about 42% generated by the U.S. electric power industry as a whole.

40. Despite the significant improvement in NorthWestern's generation capacity, including acquisitions of hydroelectric plants and wind farms, NorthWestern's resource portfolio of owned resources and long-term contracts is not yet sufficient or "reliable," as defined by regional planning organizations, including the Western Regional Adequacy Program ("WRAP"), of which NorthWestern is a founding member.

41. In periods of peak loads, NorthWestern often does not have sufficient capacity, meaning that NorthWestern must make market purchases of capacity and energy to meet customers' needs.

42. Periods of peak load are those times when customers' demand for electricity is particularly high. This tends to occur during periods of extreme weather, during the coldest winter days (below 10 degrees Fahrenheit) when more electricity is used for heating purposes and during the hottest summer days (above 90 degrees Fahrenheit) when more electricity is used

for cooling. The availability or unavailability of other resources can also be a significant factor. For example, the amount of rain during a season or snow during a preceding winter impacts the generation of our hydroelectric facilities. Similarly, there are periods when more or less wind power is generated. Unfortunately, in Montana this extreme weather typically occurs with high pressure systems, meaning our wind generates very little to zero power during these critical conditions. Those instances when there is both high demand for electricity, due to the extreme temperatures, and less available renewable generation can be particularly challenging from both a reliability and customer affordability perspective. Thus, NorthWestern is forced to rely on a market that has significant price volatility, as a reflection of the scarcity of on-demand generation. There is also increasing concern regarding the scarcity of firm transmission during these extreme weather events.

43. There are significant disadvantages to being reliant on market purchases to manage peak demand periods, especially considering the declining availability of capacity resources in the region.

44. As an initial matter, prices for electricity tend to increase when there is greater demand. Typically, NorthWestern's periods of high demand coincide with those of other utilities in the region. At the same time market prices are increasing during the critical weather events, especially winter, the available wind and solar generation frequently diminishes, sometimes to near zero. The same weather patterns that impact Montana also frequently impact other states in the region. As a result, the demand for electricity is high during such periods, which drives up the prices. Those higher prices increase our costs and ultimately lead to higher bills for customers, which impacts their household and business finances and the broader Montana economy. Importantly, the costs of electricity obtained through power purchase contracts are

substantially passed directly through to consumers. NorthWestern's lower income and smaller business customers tend to be most sensitive to the impacts of increased electric costs.

45. In addition to pricing, there is also the question of availability. Simply put, it is not prudent to assume that there will always be sufficient out-of-state power that can be both purchased and transmitted to Montana. In his Declaration, Michael Cashell discusses the limitations of the transmission system and how those impact NorthWestern's ability to bring electricity into Montana to serve NorthWestern's customers.

46. In brief, Mr. Cashell explains that there is insufficient existing transmission capacity to replace Colstrip's capacity through increased importation of electricity. It is also not plausible to permit and construct significant additional transmission capacity, much less enough to replace lost capacity at Colstrip, prior to the mid-2030's. This was a major driver of the Avista Agreement – providing NorthWestern with more reliable, highly-accredited electricity during the bridge period between now and when other sources of electricity to replace Colstrip will be reasonably available.

47. For my part, I will discuss that availability of electricity to purchase, setting aside the increasing uncertainty of whether it can be transmitted to Montana.

48. In recent years, several large power plants in Montana and adjacent states have closed. J.E. Corette, with a 163-MW nameplate capacity, was closed in 2015. Colstrip Units 1 and 2, each with nameplate capacities of 307 MWs, ceased operation in early 2020. That same year, the Boardman plant in Oregon, 601 MWs, and Unit 1 of the Centralia plant in Washington, 730 MWs, both closed. Idaho Power ended its participation in Unit 1 of the Valmy facility, 254 MWs, in 2019 and the operations there completely halted in 2021.

49. In addition to those significant retirements that have already taken place, more retirements are anticipated in the near future. In particular, Unit 2 of the Centralia plant, 670 MWs, is scheduled to cease operation in 2025, as is North Valmy Unit 2, which is 289 MWs.

50. The retirement of these necessary on-demand generation is occurring at the same time forecasters are predicting a significant increase in demand driven in part by electric vehicles and artificial intelligence development.

51. In addition, several existing dams in the Pacific Northwest are being considered for removal, constraining the future availability of hydroelectric resources.

52. In summary, there is much less reliable electrical generation available in Montana and the Pacific Northwest (the market) than in the past, and the closures scheduled for 2025 are expected to result in the loss of an additional 959 MWs of nameplate capacity by the end of that year. Importantly these losses of nameplate capacity are all for facilities for which their accredited capacity is very close to their nameplate capacity. As a result, the regional portfolio is shifting away from high-accredited to low-accredited generation sources. A difficult situation is expected to get worse and grave reliability concerns are no longer just the province of states like California and Texas that have had well publicized blackouts. A recent article by a former Federal Energy Regulatory Commissioner noted that this reliability concern has spread to over two-thirds of the Country. Given these circumstances, Colstrip is a critically important facility for NorthWestern and its Montana customers.

53. Equally importantly in terms of timing and supply, 100 MW of NorthWestern's current market contract capacity will be expiring in the near future. Given the retirements of facilities throughout the region, it cannot be assured that NorthWestern will be able to renew or replace these contracts when they expire, especially under as favorable of terms. To the extent

any can be replaced, market conditions indicate that they will be at much higher costs, which will be passed directly on to our customers.

54. As noted above, NorthWestern engages in long-term electricity supply planning.

55. These historical and upcoming developments have left NorthWestern in a critically tenuous position of potentially not being able to reliably serve its customers' needs during periods of peak loads, such as hot summer and most critically, cold winter days. Reliance upon market purchases is becoming increasingly risky in terms of reliability and affordability and is expensive and uncertain, especially during critical weather events that absent resource sufficiency, places lives at risk. This is in spite of NorthWestern acquiring a substantial amount of generation since 2011.

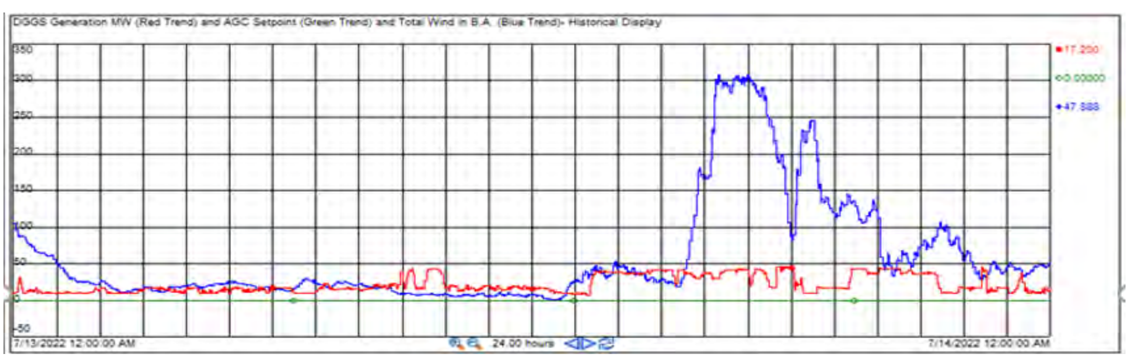
56. Based on those identified needs, NorthWestern issued a Request for Proposals (RFP) in 2020. This RFP was explicitly for **any** type of generation that was able to provide capacity for those three distinct duration categories. This RFP was conducted by an independent and respected third party. NorthWestern was not directly involved in the evaluation process. The Yellowstone County Generating Station – a natural gas fired facility, was selected as providing the best combination of attributes to supplement NorthWestern's portfolio.

57. Wind and solar have some positive attributes as sources of electricity. They do not have fuel costs, do not create emissions, and their capital costs have declined over the past decade (though current inflationary trends and supply chain issues are having large cost and availability impacts, as in other areas of the economy). However, like any other type of electric generation, they also have downsides. In terms of reliably serving our customers, one important disadvantage of intermittent generation renewables is that the amount of electricity they generate varies significantly based on the weather. This is reflected by the previously discussed large

difference between their nameplate and accredited capacities – values determined outside of NorthWestern by regional planning agencies.

58. Battery storage (4 hour duration) is also a tool utilities, especially in the Southwest, are using. This resource works well for helping address daily 4 *hours* of peak demand. Montana's system has a 4 *day* problem wherein the storage would only work for 4/96ths hours. To replicate how storage operates in state like California, NorthWestern would to have 24 times the quantity of storage to serve these events, which is cost prohibitive.

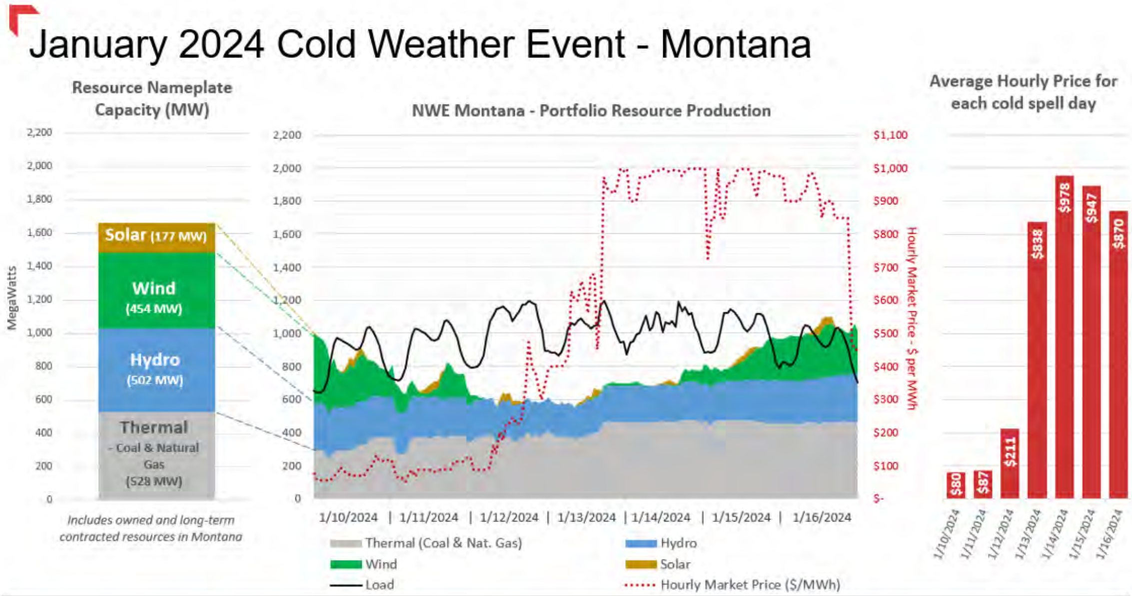
59. To illustrate that point, I have included two charts below. The first chart shows the amount of electricity generation, in MW, over a 24-hour period on July 13, 2022 from (1) all the wind generation resources within the NorthWestern Balancing Authority, which is depicted in blue, and (2) the generation from NorthWestern's Dave Gates Generating Station, depicted in red. The y-axis, with the values in ascending order on the left side, represents MWs of generation. The x-axis represents hours of the day.



60. Focusing on the wind, the chart shows that after about 2:00 am there was little to no electricity from wind generation on the system until the afternoon. Then, following a slight increase in the early afternoon, wind generation jumped from less than 50 MWs to more than 300 MWs between 3:30 and 4:30 pm. It then declined to less than 100 MWs at 5pm before ramping up again once more between 6:00 and 7:00 pm and then declining. As this example

shows, the amount of electricity generated by wind facilities can quickly and significantly change. NorthWestern, however, must continue to balance at all times the electricity demands of customers with the amount of electricity supplied. This balancing is imperative; deviations between generation and customer demand of relatively tiny percentages for even a small amount of time (seconds to minutes) will lead to system instability, customer equipment damage, and blackouts.

61. During the Winter of 2023-2024, thermal generation, especially Colstrip, played a key role in helping provide reliable and affordable service. The variable cost of operating Colstrip was about $23/MWh. Unfortunately, NorthWestern's customers were subject to extreme market prices from NorthWestern's market contracts. As an example, market contracts cost our customers up to $900/MWh. NorthWestern purchased about $40 million of power during this 6 day critical weather period, which had wind and solar underperforming, even less than their accredited capacity.



Once again during the recent cold spell (1/10/24 to 1/16/24), energy prices surged when wind and solar weren't providing capacity. And once again, NorthWestern had to be dependent on the market to meet customer needs, with the average price of a megawatt hour over $900 for the last 4 days (13th-16th) of the cold spell.

62. As of December 8, 2023 future prices for heavy load electricity for the months of July, August and September, 2024 are trading at $130, $180, and $136 per MWh respectively. Further contracted prices have ranged from $200 to $900 per MWh during recent peak events. The actual cost for purchasing electricity in December 2022 was around $250 per MWh; for the three highest load days (December 21-23), the actual purchase cost averaged about $440/MWh. To provide a simplified illustration of the impact of such a potential difference in cost to serve customers, consider a hypothetical three-day event during which NorthWestern's share of Colstrip would produce about 15,000 MWh. If the difference between the market price and the variable cost of Colstrip is $400/MWh, the cost of market purchases for the three day period would be about $6 million more than the cost of generation ($400 x 15,000 MWh = $6 million). Such extra costs of a contracted capacity resource would be passed on to customers.

63. My statements in the preceding paragraphs assume that a capacity contract is even available. However, I stress again that this may not be the case given the recent and planned

closures of multiple plants in neighboring states. I also do not believe that transmission would be available even if we located a source from which we could purchase capacity (especially with the closure of Colstrip), which Michael Cashell addresses in his Declaration.

64. As undesirable as it would be for NorthWestern to have to purchase capacity on the market as an alternative to Colstrip, the scenario in which we are not able to obtain needed capacity (and/or are not able to obtain transmission for such capacity) is much worse. Under this scenario, the possibility of rolling blackouts during periods of extreme weather becomes more likely. The rolling blackouts in California during the summer of 2020 and the multi-day blackout in much of Texas during February, 2021 show that utility systems in the United States can experience significant and damaging capacity shortfalls. During the cold snaps in the winters of 2022-23 and 2023-24, the Montana electrical grid was stressed to the maximum. A significant transmission or supply generation resource failure would have likely led to being unable to serve customers.

65. Equally importantly to the raw amount of electricity available, Colstrip plays a critical voltage-maintenance function. Closure would therefore require major investments in voltage maintenance, independently of the concerns about market electricity availability and transmission capacity. These concerns are discussed in more detail at page 59 of the 2023 IRP.

66. If NorthWestern is not allowed to obtain the capacity it needs, customers and communities could also suffer from blackouts. Blackouts cause serious property damage, business disruption, and even death. It is estimated that approximately 250 people died in Texas as a direct consequence of the 2021 power disruptions. This was when temperatures were in the teens. This past January our Montana service territory experienced temperatures as low as -45°F in our towns. Rural areas likely experienced even colder temperatures.

67. Customers rely on electricity to power their health care and other personal devices, cool their homes, heat some homes (often our lower-income customers living in mobile homes and apartments with electric baseboard heating), and power important infrastructure, including gas pumps. Natural gas appliances also rely on electricity for ignition and, in the case of forced air furnaces, fans.

68. Even when customers have generators, as some critical infrastructure customers do, there is a limit to how much fuel is stored on site at each individual location. These factors all contribute to a significant environmental justice component to reliable electrical supply.

69. NorthWestern also cannot realistically construct 444 MW of new capacity in Montana to replace our current and future (starting in 2026) interest in Colstrip by the MATS2 compliance date of July 2027. This arises from both timing and regulatory constraints. From a timing perspective, it takes several years to bring new generation on-line. As illustrated by YCGS – the most recent significant generation project – the YCGS development process commenced in 2019 and YCGS is only now coming on-line. 444 MW of capacity would be more than double YCGS and correspondingly more difficult to construct and permit.

70. Additional renewables would not reliably replace Colstrip, because of the associated intermittency issues. Additional coal capacity is infeasible for the same reasons as will result in result in shutdown of Colstrip by the end of 2031 under the GHG Rule. And additional natural gas capacity is problematic, both because of the CCUS requirements on new natural capacity under the GHG Rule, and because there is insufficient natural gas supply and pipeline capacity in Montana to bring hundreds of additional MW on line by the end of 2031, much less mid-2028.

71. NorthWestern is seriously examining using a small nuclear facility as a long-term facility to replace Colstrip, but no such facility presently has been constructed or can realistically be constructed and operational prior to the mid-to-late 2030s, at the earliest.

72. For the foregoing reasons, Colstrip's capacity cannot reasonably and timely be replaced prior to the mid-2030's. Closure of Colstrip before then would create significant grid reliability risks in Montana.

EPA's Responses to NorthWestern's Comments on the MATS2 Proposed Rule were incorrect or non-responsive.

73. NorthWestern made all the reliability-oriented points discussed in Paragraphs 23-71 in its NorthWestern MATS2 Comments. EPA very briefly responded to these concerns on pages 52-53 of EPA's "Summary of Responses to Comments and Reponses on Proposed Rule." (EPA-HQ-OAR-2018-0794-6922). The entirety of EPA's response is the following:

> Regarding comments about the impact of closing Colstrip on reliable electrical service, facilities may request an additional time extension through the Department of Energy under the Federal Power Act section 202(c), which are made on a case-by-case basis based on a substantial need for grid reliability. In addition, as other commenters have noted, NorthWestern Energy has recently joined the Western Resource Adequacy Program ("WRAP"), a regional reliability planning and compliance program in the West.

74. Turning first to EPA's observation that NorthWestern has joined WRAP, this is a correct statement, as discussed in detail in NorthWestern's 2023 IRP at Section 3.4. NorthWestern is a founding member of WRAP, and as the IRP states: "One of the program objectives is to leverage the geographic diversity benefits of the larger region to enhance planning and operations during times of peak energy demand. The ability of WRAP participants to pool and share resources during tight operating conditions is expected to lead to increased reliability and potential savings opportunities." A condition of a utility's ability to even participate in WRAP is a portfolio that can already meet WRAP's reliability criteria. WRAP has

never and in fact specifically excludes the function of serving as a capacity market alternative. It is only intended to provide economic efficiency. None of this changes the fact that NorthWestern is transmission-and-capacity constrained, as is the Western Interconnection. Indeed, NorthWestern's ability to comply with its WRAP commitments is premised on continued operation of Colstrip at least through the mid-2030's. Participation in WRAP does not alter or mitigate any of the consequences of early closure of Colstrip or the cost-effectiveness of compliance with the MATS2 Rule.

75. This leaves EPA's invocation of Federal Power Act section 202(c) ("FPA Section 202(c)"). EPA raised this supposed avenue for a compliance extension to NorthWestern during discussions following the close of the comment period, during the pendency of the Proposed Rule. NorthWestern has reviewed historic examples of the use of Section 202(c), and none are in any way comparable to the compliance issues facing Colstrip and NorthWestern. In all but one historical example, FPA Section 202(c) orders were granted to temporarily waive existing capacity limits or operation of *existing* installed pollution controls. The single historical counter-example dates from twenty years ago, and only provided an emergency exemption for a few months. FPA Section 202(c) has never been used to provide a significant extension to EPA-imposed deadlines on the installation of pollution controls in the first instance. Moreover, in this context an extension that does not take NorthWestern all the way to the GHG Rule end-of-2031 retirement deadline (and thereby allow NorthWestern to avoid installation of the fPM controls altogether) would not result in any significant cost savings, and indeed would make the MATS2 Rule even less cost-effective than it already is. Further errors in the EPA invocation of FPA Section 202(c) authority are addressed by counsel.

I declare under penalty of perjury pursuant to 28 U.S.C. § 1746 that the foregoing is true and correct.

DATED this 27th day of June, 2024.

John Hines

By: s/ John D. Hines
John D. Hines

I, Serena K. Wetherelt, hereby declare as follows:

1. I am over 18 years of age and reside in Lame Deer, Montana. I am President of the Northern Cheyenne Tribe.

2. The Northern Cheyenne Tribe has been a federally recognized Indian tribe since the Friendship Treaty of 1825. The Tribe now occupies the Northern Cheyenne Reservation, which is composed of approximately 444,000 acres of land in Big Horn County and Rosebud County, Montana. The Tribe has approximately 11,000 members, many of whom live on or near the Reservation.

3. The Northern Cheyenne Reservation is approximately 20 miles south of the Colstrip power plant. About 100 Northern Cheyenne Tribal members are employed by the Colstrip plant or the adjacent Rosebud mine that supplies coal to Colstrip. Many Tribal members also live in the town of Colstrip.

4. As explained below and in the Tribe's prior comments to EPA (attached as *Exhibit A)*, the Northern Cheyenne Tribe supports the U.S. Environmental Protection Agency's rule strengthening limits on toxic air pollution from coal plants such as Colstrip, the "Mercury and Air Toxics Standards Strengthening Rule." Colstrip's timely compliance with the new limits will improve air quality and benefit the health of tribal members. Additionally, although the Tribe does not advocate for the closure of the Colstrip plant, in the

event of closure, the Tribe's development of clean-energy resources offers viable alternative energy sources that benefit the local economy.

Colstrip's Compliance with the Mercury and Air Toxics Standards Strengthening Rule Will Improve Local Air Quality and Public Health of Northern Cheyenne Tribal Members

5. The Northern Cheyenne Tribe has taken steps to protect air quality and the health of tribal members living on and near the Reservation. Concerned about the proposed construction of Colstrip Units 3 and 4, in 1976 the Tribe proposed to redesignate the Reservation as a Class I airshed under the Clean Air Act. After EPA approved the Tribe's proposal in 1977, granting special protection for air quality and visibility protection on the Reservation, the Tribe exercised its authority to require additional air pollution controls on the new Colstrip units. And in 2007, the Tribe and EPA entered a consent decree with Colstrip's owners that required the installation of equipment to reduce the plant's harmful nitrogen oxide emissions.

6. While these efforts have protected air quality on the Northern Cheyenne Reservation to a significant degree, Lame Deer is designated federally as a nonattainment area for large particulate matter (PM10) pollution. This means that particulates in the air exceed federal limits established to protect public health.

7. Hazardous air pollutants and the particulate matter emitted with these pollutants are known to cause and exacerbate health problems, including lung

cancer and other respiratory illnesses such as asthma, particularly among children and elderly individuals.

8. Incidence of cancer, lung cancer, and asthma in Rosebud County, and on the Northern Cheyenne Reservation in particular, are elevated compared to the rest of Montana.

9. I understand that Colstrip's emissions of non-mercury metal air pollution—which includes lead, nickel, and chromium and is measured as filterable particulate matter—are currently two to three times the new limit that EPA adopted based on industry-wide improvements in pollution control. These non-mercury metals are inherently hazardous and are classified as known or probable human carcinogens. Colstrip Units 3 and 4 are the highest and third-highest emitters of such pollution in the country.

10. Because most Northern Cheyenne Tribal members live on and near the Reservation—including in the town of Colstrip—and many Tribal members are employed at the Colstrip power plant and nearby Rosebud mine, they are disproportionately exposed to Colstrip's hazardous air pollution.

11. Colstrip's compliance with the new limits would reduce hazardous air pollution and therefore improve the health of Tribal members living on and near the Reservation.

Investment in Tribally Developed Wind, Solar, and Storage Resources Would Limit Local Economic and Resource Adequacy Impacts Due to Colstrip's Eventual Closure

12. I understand that in their challenges to the Mercury and Air Toxics Strengthening Rule, the State of Montana, Talen Energy, and NorthWestern Energy claim that the Colstrip plant may retire rather than invest in new pollution controls necessary to meet the new hazardous air pollution limits. The Tribe does not advocate for closure of the plant, but the Tribe recognizes that the plant will close eventually, whether due to the EPA's new air pollution rules, the age of the plant, or market conditions.

13. NorthWestern Energy has an opportunity (and has had opportunities) to plan for such closure by investing in Tribal energy resources. The Northern Cheyenne Tribe is helping to lead the transition to a clean energy economy through renewable energy development consistent with our cultural beliefs. Investment in wind, solar, and storage projects offer a means to help provide jobs for tribal members and members of the surrounding community, to work toward tribal energy independence and statewide resource adequacy, and to help contribute to a cleaner environment.

14. The Northern Cheyenne Tribe has consistently advocated for planning by Colstrip's owners and the Montana Public Service Commission for Colstrip's eventual closure, including plans for an economic transition of local communities

(including the Northern Cheyenne Tribe) and for the development of clean energy resources to replace Colstrip power.

15. In February 2019, the Tribe submitted testimony in NorthWestern Energy's general rate case before the Montana Public Service Commission urging NorthWestern Energy to assist the Tribe in planning for a transition to renewable energy resources to replace coal and for the economic transition of the tribal economy. *See Exhibit B.*

16. In 2023, the Tribe submitted comments on NorthWestern Energy's Integrated Resource Plan, noting that the Tribe is developing significant wind and solar energy resources that could help NorthWestern Energy meet customer demand. *See Exhibit C.* Because those projects will be developed under the Tribe's leasing and review framework (rather than state or federal frameworks) and are in close proximity to the Colstrip Transmission System, they could become operational within a short (less than two years) period of time. Additionally, the Tribe's comments observed the significant economic incentives under the Inflation Reduction Act for siting such energy projects on the Northern Cheyenne Reservation, greatly improving their affordability for NorthWestern and its customers. The comments state:

> The Northern Cheyenne Tribe has determined that responsible development of the Northem Cheyenne Tribe's renewable energy resources can provide for economic development of such resources in a manner that maximizes

> the benefits to the Tribe and is consistent with the Tribe's traditional, cultural, and environmental values. And while clean energy development on the Reservation benefits the Tribe and its members, investment by NorthWestern Energy in such development would additionally provide economic opportunities to the communities near the Reservation, as well as extraordinary benefit to the utility's Montana electric customers. At the same time, NorthWestern's plan to expand its reliance on Colstrip power would harm the Tribe without providing corresponding economic and environmental benefits.

Exhibit B at 1.

17. Investment by NorthWestern Energy and other Colstrip owners in the Northern Cheyenne Tribe's clean-energy projects would help offset any statewide energy shortfall due to Colstrip's closure, while providing significant economic benefits to the Tribe and tribal members.

18. Any delay in Colstrip's compliance with the Mercury and Air Toxics Standards Strengthening Rule would unreasonably defer important air quality and health benefits for Northern Cheyenne Tribal members who are disproportionately impacted by Colstrip's toxic air pollution. And it would only prolong NorthWestern Energy's and Talen's failure to plan for the future beyond Colstrip.

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

Executed on July 15, 2024 in Lame Deer, Montana.

Serena K. Wetherelt

Serena K. Wetherelt

Exhibit A

Declaration of President Serena K. Wetherelt

-WOHEHIV-
The Morning Star

NORTHERN CHEYENNE TRIBE
ADMINISTRATION

P.O. BOX 128
LAME DEER, MONTANA 59043
(406) 477-6284
FAX (406) 477-6210

-WOHEHIV-
The Morning Star

June 23, 2023

Sarah Benish
Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Re: Proposal on National Emissions Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, **Docket ID No. EPA–HQ–OAR–2018–0794**

Dear Ms. Benish:

I write on behalf of the Northern Cheyenne Tribe, a federally recognized Tribe based on the Northern Cheyenne Reservation in southeastern Montana, to urge EPA to finalize protective Mercury and Air Toxics Standards (MATS) and to reject claims by the owners of the Colstrip coal plant that would continue to subject tribal members to unhealthy air.

The Northern Cheyenne Reservation is twenty miles from Colstrip, Montana and the Colstrip coal-fired power plant. Since the Colstrip plant was first proposed, the Tribe has taken steps to protect its people from the harmful effects of air pollution from the plant, which disproportionately impacts tribal members. For example, concerned about the proposed construction of Colstrip Units 3 and 4, in 1976 the Tribe proposed to redesignate the Reservation as a Class I airshed under the Clean Air Act. After EPA approved the Tribe's proposal in 1977, the Tribe exercised its authority to require additional air pollution controls on the new Colstrip units.

The Tribe supports EPA's efforts to establish appropriate limits on Colstrip's emissions of hazardous air pollutants. EPA explains, exposure to these pollutants harms human health, including "potential neurodevelopmental impairment, increased cancer risks, and contribution to chronic and acute health disorders, as well as adverse impacts on the environment." Final Rule, Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding, 88 Fed. Reg. 13,956, 13,968 (Mar. 6, 2023). Because of the proximity of the Northern Cheyenne tribal members to the Colstrip plant—living both on the Reservation and in the nearby community of Colstrip, where many tribal members are employed—they are disproportionately impacted by exposure to hazardous air pollutants.

Although cost-effective pollution controls are available to reduce toxic air emissions from Colstrip Units 3 and 4, namely baghouses and electrostatic precipitators, Colstrip's owners have refused to install them. As a result, Colstrip has the highest rate of filterable particulate matter emissions (a surrogate for non-mercury hazardous air pollutants) in the country and is the only plant still operating without industry-standard particulate matter controls. Colstrip has a history of exceeding even the current standard for non-mercury hazardous air pollutants.

Two of Colstrip's owners—NorthWestern Energy and Talen Montana—and Rosebud mine owner Westmoreland oppose EPA's proposal to strengthen the MATS to align with Clean Air Act requirements. According to the companies, compliance with lower limits for non-mercury hazardous air pollutants would be too costly. Such arguments irresponsibly ignore the acute health effects—including premature deaths—that Colstrip's toxic emissions have on Northern Cheyenne tribal members and the many others who live in close proximity to the plant.

The Tribe urges EPA to finalize protective MATS. Under the new standards, Colstrip Units 3 and 4 should be required to install the same controls that other plants around the country have already installed and to operate those controls to achieve maximum emissions reductions, as the Clean Air Act requires. 42 U.S.C. § 7412(d)(2), (f).

Respectfully,

William Walks Along

William Walks Along, Tribal Administrator
Northern Cheyenne Tribe

Exhibit B

Declaration of President Serena K. Wetherelt

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF THE Application by NorthWestern Energy for the Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design	REGULATORY DIVISION Docket No. D2018.2.12

THE NORTHERN CHEYENNE TRIBE

INTERVENOR TESTIMONY FROM MR. WILLIAM WALKSALONG,

TRIBAL ADMINISTRATOR

February 12, 2019

The Northern Cheyenne Tribe ("Tribe"), a federally-recognized Indian tribe located in southeastern Montana, is an intervening party in this case. The Tribe's Reservation's northern boundary is approximately 20 miles from the Colstrip Power Plant, and well over 100 Tribal members work in either the power plant or associated mines. Tribal members also reside off-Reservation in the NorthWestern Energy service area and are rate paying customers. The Tribe sought and was granted intervention based on the interest of off-Reservation, rate-paying members, as well as the economic and social impact of Colstrip Power Plant operations on the Tribe and its members.

The direct testimony provided is from William Walksalong, who is a Tribal member residing on the Reservation and the Tribal Administrator.

<u>Testimony</u>

Q: Hello Mr. Walksalong, can you please inform the Montana Public Service Commission who you are and what experience you have relative to this case?

Mr. Walksalong: Yes. My name is William Walksalong and I am a member of the Northern Cheyenne Tribe. I am a resident of Lame Deer, Montana, on the Northern Cheyenne Tribe's Reservation. I have been heavily involved in Tribal government since 1992. Prior to my current position as the Tribal Administrator I have served as Tribal President, on the Tribal Council, and in other positions. I am knowledgeable with respect to the Tribe's history, government, membership, and conditions on the Reservation.

Q: What is the purpose of your testimony?

Mr. Walksalong: The purpose of my testimony is to provide background regarding the Northern Cheyenne Tribe and its members, and information regarding the impacts to the Northern Cheyenne Tribe and Tribal members from the operation, and potential closure, of the

Colstrip plant. I also propose steps NorthWestern Energy should take to meet its obligation to minimize and compensate for those impacts.

Q: Thank you. Can you please provide background information on the Tribe and the Reservation?

Mr. Walksalong: The Northern Cheyenne Tribe has been a federally-recognized Indian tribe since the Friendship Treaty of 1825. The Tribe's ancestral homelands were first described on "paper" in the Fort Laramie Treaty of 1851. On the northern boundary, they extend from the Pemmican Mountains at the mouth of the Powder River in present-day Montana, east to the confluence of the Missouri and Cannonball rivers in present-day North Dakota. The Rocky Mountain Front marks the western boundary with Pike's Peak, known to the Northern Cheyenne people as Stonehammer Mountain, in the southwestern corner. The Arkansas River forms the southern boundary, and the confluence of the North and South Platte rivers are on the eastern boundary. These homelands include all of the Powder River Basin in present-day Montana and Wyoming.

The Tribe now occupies the Northern Cheyenne Reservation, which is composed of approximately 444,000 acres of land in Big Horn County and Rosebud County, Montana. More than 99 percent of lands within the Reservation are owned by the Tribe or its members and held in trust by the United States. The Tribe also possesses off-Reservation trust lands, including more than 500 acres along the Tongue River Reservoir, in close proximity to the Decker and Spring Creek coal mines in Montana. The Tribe has over 11,000 members, most of whom live on or near the Reservation.

Q: How was the Reservation established?

Mr. Walksalong: The Northern Cheyenne people have a long and proud history of fighting for their homelands in the Powder River Basin. This history is set forth in a report titled *The Northern Cheyenne Tribe and Its Reservation* (Apr. 2002), as well as in the books *A History of the Cheyenne People* by Tom Weist (1977) and *The Northern Cheyenne Indian Reservation, 1877-1900* by Orlan J. Svingen (1993). I will provide a brief summary.

The Northern Cheyenne have been living in southeastern Montana since before contact by white settlers. Beginning in the early 1800s, large numbers of settlers and gold seekers began to move into southeastern Montana. These early settlers and miners brought with them diseases that ravaged large numbers of our people. They also brought European cattle, which began to disrupt the grazing and migration patterns of the buffalo, which the Northern Cheyenne relied on for subsistence and ceremonial purposes. These encroachments, which did not respect the territorial and cultural interests of the Cheyenne and other Indian people, resulted in decades of war.

In the mid-1800s, there were numerous attempts to remove the Northern Cheyenne from our homeland near the Tongue River and relocate them to other parts of the West. For example, the 1851 Treaty of Fort Laramie anticipated the removal of the Cheyenne to lands south of the North Platte River; however, following treaty execution, many Northern Cheyenne people continued to live and hunt in their traditional homeland, leading to escalating conflict and violence in the 1850s. In 1861, the U.S. government again attempted to relocate the Northern Cheyenne to the south, but we refused to abandon our traditional hunting grounds and continued to resist the commercial and military intrusions into their territories. Conflict continued into the 1870s, as the U.S. military sought to open the Cheyenne lands to settlers and gold miners, and the Northern Cheyenne sought to protect their lands and traditions from encroachment. These conflicts include the 1876 Battle at Little Big Horn, where the Northern Cheyenne allied with the Sioux and Arapaho to defeat General George Armstrong Custer and the U.S. Seventh Calvary. They also include the Battle of the Tongue River in 1877 (also known as the Battle of Wolf Mountain), where a group of Northern Cheyenne battled a detachment of the Fifth Infantry in the project area, along the eastern bank of the Tongue River near the present-day location of Birney.

Following these conflicts, many Northern Cheyenne were forcibly relocated to the Oklahoma Territory in 1878 as retribution for our resistance to non-Indian domination and our participation in the Battle of the Little Bighorn. However, we (unlike other relocated tribes) trekked back to our historic homeland in Montana. This journey came at great cost to the Tribe - death, imprisonment, and other deprivations – as we were hounded along the way by thousands of hostile military and settlers.

In 1878, following the relocation to Oklahoma, Chief Dull Knife and Chief Little Wolf led bands of Northern Cheyenne on a long and arduous return trip from Oklahoma to their traditional homeland. In the late 1870s and early 1880s, the Northern Cheyenne began to reestablish themselves in areas near the Tongue River, settling on Lame Deer Creek, Muddy Creek, Rosebud Creek, and the Tongue River between Otter Creek and Hanging Woman Creek. Recognizing the importance of this area to our people, President Arthur signed an executive order on November 16, 1884, establishing the Tongue River Indian Reservation, which at that time did not include lands settled by the Northern Cheyenne on the Tongue River itself. However, in 1900, President McKinley signed an executive order changing the name of our Reservation to the "Northern Cheyenne Reservation" and extending the eastern boundary of our Reservation to its current location on the Tongue River.

Despite establishment of the Reservation, Northern Cheyenne lands and culture remained under threat throughout the 20th century. The early 1900s saw the forced acculturation of my people through federal policies that prohibited or discouraged traditional cultural and religious practices and sent Cheyenne children to boarding schools where they were forbidden to speak their native language.

Through all this hardship, the Cheyenne people have persevered. We are very proud to live on our homelands, and we place a high priority on protecting our lands and waters.

Q: Where do Tribal members work on or near the Reservation, and what are the economic conditions?

Mr. Walksalong: In general, the economy in our area has struggled. Rosebud County, where most of the Reservation and the town of Colstrip are located, was recently designated an "Economic Opportunity Zone" under the 2017 Tax Cuts and Jobs Act, in recognition of ongoing unemployment and poverty. Big Horn County, where the remainder of the Reservation is located, is also designated as an Economic Opportunity Zone.

Within Rosebud County, economic conditions on the Reservation are far worse than off-Reservation. It is very challenging to find work on or near the Reservation. As part of commenting on a proposed railroad near the Reservation, the Tribe commissioned a report from Dr. Thomas Power, which he completed in 2015. While the data may have changed slightly since that time, I believe the identified trends are largely accurate. In comparing on-Reservation conditions to off-Reservation conditions in Rosebud County, Dr. Power noted that:

- The Northern Cheyenne population is much younger when compared with surrounding areas. In Rosebud County, the median age on-Reservation is 23 and off-Reservation is 43.

- The Northern Cheyenne Reservation is much more densely populated. The non-Reservation areas have 1.3 persons per square mile, while the Northern Cheyenne Reservation has a population density of 6.8 persons per square mile.
- The Northern Cheyenne population is much poorer than the population in the surrounding counties. On a per capita basis, in the predominantly white off-Reservation population in Rosebud County, people have 109% higher income per person than their predominantly American Indian neighbors on the Reservation: $12,559 on-Reservation versus $26,271 off-Reservation.
- The unemployment rate on the Reservation is almost 14 times that found off the Reservation in Rosebud County: 27% on-Reservation versus 2% off-Reservation. This is despite the fact that the Northern Cheyenne are overall a well-educated group when compared to Rosebud County and the United States as a whole.

As you can see from these figures, the economy on the Reservation faces challenging circumstances and is fragile. These circumstances leave the Tribe and its members especially vulnerable to changes at Colstrip Power Plant or the associated mines.

Q: What has the Tribe's position been regarding coal development?

Mr. Walksalong: In the Northern Cheyenne religion and culture, land is sacred, and people should not open up the earth. As a result, the Tribe has generally opposed coal mining on its lands. This opposition was solidified in the 1960s and 70s, when coal companies sought to take advantage of the Tribe and gained undermarket leases on the Reservation. It took an act of Congress and a U.S. Supreme Court case, *Northern Cheyenne Tribe v. Hollowbreast*, 425 U.S. 649 (1976), to protect the Reservation from those leases. Since that time, the Tribe has actively sought to ensure mining proposed near the Reservation follows all applicable laws, and that project planners carefully consider impacts to the Tribe and its members.

While the Tribe has historically opposed coal development, the Tribe has also worked closely with owners of the Colstrip Power Plant and associated mines. The Tribe has generally supported operations so long as the owners and operators of the plant and mines follow applicable laws and respect the Tribe's sovereignty. The Colstrip jobs most of all are central to our economy.

Q: How does the Tribe benefit from operation of Colstrip Power Plant and associated mines?

Mr. Walksalong: Well over 100 Tribal members work at the power plant and the mines. I think that this has been a good relationship – the Tribe provides high-quality, local workers, and benefits from generally good union jobs with locally competitive wages.
On the Reservation, each job associated with the Colstrip Power Plant directly supports approximately ten members. This means that the operation of the Power Plant directly benefits more than 1,000 Tribal members (approximately ten percent of the on-Reservation population), and indirectly benefits many more.

These jobs have enormous importance, because they are generally high wage jobs with good benefits, that up until recently have been considered very reliable. Tribal members have received training and certifications, which helps improve the Tribal workforce and provide more opportunities. Plant and mine owners and operators also provide some scholarship opportunities to Tribal members and funding to the Tribe's Department of Environmental Protection and Natural Resources.

Q: How is the Tribe adversely affected by coal mining and operation of the Colstrip Power Plant?

Mr. Walksalong: The Northern Cheyenne Reservation is surrounded by coal mines, including the Western Energy (Rosebud) mine to the North and the Decker and Spring Creek mines to the South. When these mines were under development, they promised opportunities for employment and contracting in Northern Cheyenne reservation communities, but those opportunities never fully materialized.

Coal mining near the reservation impacts tribal communities. Air pollution from mine activities impacts our Class I airshed. Runoff from mines impairs water quality. In particular, runoff from the Decker Mine discharges into the Tongue River, which forms the eastern boundary of the Reservation. Mining destroys habitat for sensitive species, including burrowing owls, prairie dogs, prairie chicken, and sage grouse. Mining within Northern Cheyenne ancestral homelands also destroys important cultural sites, including sites used for Cheyenne ceremonies.

Coal mining near the Reservation brings in workers, which has tended to produce off-Reservation economic benefits while imposing social and economic costs on the Reservation. Outside workers sometimes view the Reservation as a lawless zone and have brought crime, trash, and illegal drugs onto the Reservation. This imposes a significant cost on the Tribal government and harms the quality of life of the Tribe's members.

Operation of the Colstrip Power Plant impacts air quality on the Reservation. The Tribe conducts on-going air quality monitoring. Particularly when scrubbers or other equipment fails, pollutants are registered on the Reservation.

Q: How does this history and context relate to rate setting for NorthWestern Energy?

Mr. Walksalong: The power plant and associated mines have both positive and negative impacts on the surrounding communities. Among those communities, the Tribe and its members are disproportionately reliant on those benefits, and disproportionately harmed by the negative impacts.

My understanding is that a big part of NorthWestern Energy's rate-setting process involves future planning for Unit 4 of the Colstrip Power Plant. Those considerations involve how to plan for potential closure and how to account for the costs of operations, closure, and remediation. The determination of these issues will have an enormous economic and social impact on the Tribe and its members. How NorthWestern approaches potential closure determines how much money it plans on spending, which in turn affects rates.

I am aware that in prior rate-setting cases for Puget Sound Energy and Avista Corp., companies which also own shares of Colstrip Power Plant, there have been substantial settlements that purport to compensate the affected communities for likely plant closure. Despite the unique impacts of closure on the Tribe, the Tribe has been excluded from the bodies that will distribute funds generated by these settlements. At this time, it appears that the Tribe and its members are unlikely to receive any compensation. This is not a feature of whether the Tribe should, as a matter of common sense and fairness, received such funding. The Tribe has been shut out of those processes and have had limited resources to dedicate to this endeavor. For example, despite the Tribe's major stake in the future of the Colstrip plant and mine, we were not invited to be a member of the Governor's Colstrip Community Impact Advisory Group.

Q: What measures do you think NorthWestern Energy should take to compensate the Tribe and its members for the impacts of operation of Colstrip Power Plant, the associated mines, and potential closure of those facilities?

Mr. Walksalong: The most important principle is that companies such as NorthWestern should not be allowed to benefit and profit from operation near the Reservation, and then leave the Tribe and its members to bear the consequences of closure. There must be adequate measures in place to ensure that the Tribe is not disadvantaged by closure. If not, the Tribal economy will likely be devastated by dramatically increased unemployment. Additionally, any struggles in Colstrip are also likely to spread to the Reservation, and the Tribe will have to deal with the social consequences of unemployment. This will lead to increased crime on the Reservation and the Bureau of Indian Affairs law enforcement is severely underfunded and has only a few officers working on our vast Reservation. And we do not have a tax base to help fund law enforcement activities like off-Reservation municipalities enjoy.

While the details require specific negotiation, a plan for closure must seek to do two things: minimize impacts to Tribal members and compensate for the impacts that occur. To minimize environmental impacts, NorthWestern Energy must commit to complete cleanup and remediation of all affected resources, including soil contamination, groundwater contamination, and impacts to surface waters from the power plant and associated mines. This commitment must include setting aside adequate funds now, in the event of bankruptcy or a faster-than-anticipated closure.

To minimize economic impacts, NorthWestern Energy should agree to prioritize Tribal members, particularly those already employed at the power plant or the mine, in jobs associated with closure and remediation. For many years the owners of the Colstrip plant and mine have by contract given employment preference to Tribal members, and that should continue. My understanding is that closure and remediation could take decades and involve ongoing employment. This process should seek to employ as many Tribal members as possible. To the extent specialized skills or new certifications are required, NorthWestern should provide trainings to Tribal members.

NorthWestern should also assist the Tribe and the region to transition to the renewable energy sources that replace coal. The Tribe is in the process of developing potential wind, solar, and biomass electricity generation on the Reservation. NorthWestern should facilitate that development by agreeing to buy power at above-market rates, and by offering greatly reduced transmission costs to outside buyers. These measures would help to jumpstart an industry that promises to provide sustainable jobs for the region into the future.

To compensate for the impacts of operations and closure, NorthWestern should provide funds for the Tribe to facilitate the transition to a new economy. The prior rate-setting cases for Puget Sound Energy and Avista are helpful examples. Avista owns 15% of Unit 3 and 15% of Unit 4, and Avista agreed to a settlement of $4.5 million as part of its acquisition by Hydro One. This amount is proportionate to a larger settlement of approximately $10 million paid by Puget Sound Energy. Because NorthWestern owns 30% of Unit 4, the same overall ownership as Avista, $4.5 million is an appropriate and necessary amount for a settlement fund.

Because the Tribe has been excluded from prior settlement funds, and bears a disproportionate impact from closure, the Tribe should either receive settlement funds directly from NorthWestern Energy or be guaranteed controlling representation on the body that distributes funds. While the Tribe would control these funds, based on past experience, I anticipate they would be used for measures such as scholarships for Tribal members and startup capital for businesses owned by the Tribe or its members.

I strongly believe that with appropriate planning and resources, a strong economy on the Reservation will help fuel a strong economy in Rosebud County.

Q: Thank you. Do you have any further thoughts?

Mr. Walksalong: That completes my direct testimony in this matter.

Respectfully submitted on this 12th day of February, 2019.

DarAnne Dunning
Luxan & Murfitt, PLLP
Montana Club Building
24 West Sixth Avenue, Fourth Floor
P.O. Box 1144
Helena, Montana 59624-1144
Phone: (406) 442-7450
Fax: (406) 442-7361

On behalf of Intervenor the Northern Cheyenne Tribe

CERTIFICATE OF SERVICE

I hereby certify that on the 12th day of February, 2019, I served *The Northern Cheyenne Tribe Intervenor Testimony from Mr. William Walksalong, Tribal Administrator*, by first-class mail, postage prepaid, and electronic mail, unless otherwise noted, on the following:

Will Rosquist
Justin Kraske
Jeremiah Langston
Public Service Commission
1701 Prospect Ave.
P.O. Box 202601
Helena, MT 59620-2601
wrosquist@mt.gov
jkraske@mt.gov
jlangston@mt.gov

NorthWestern Energy
Al Brogan
Sarah Norcott
Ann B. Hill
NorthWestern Energy
208 N. Montana, Suite 205
Helena, MT 59601
al.brogan@northwestern.com
ann.hill@northwestern.com
sarah.norcott@northwestern.com

Joe Schwartzenberger
Tracy Killoy
NorthWestern Energy
11 East Park
Butte, MT 59701-1711
joe.schwartzenberger@northwestern.com
tracy.killoy@northwestern.com

For electronic service only:
connie.moran@northwestern.com
heather.grahame@northwestern.com

Montana Consumer Counsel
Robert Nelson
Jason Brown
Suzanne Snow
Montana Consumer Counsel
111 N. Last Chance Gulch, Suite. 1B
P.O. Box 201703
Helena, MT 59620-1703
robnelson@mt.gov
jbrown4@mt.gov
ssnow@mt.gov

Montana Department of Environmental Quality (DEQ)

Sean Slanger
Jackson, Murdo, and Grant
203 North Ewing
Helena, MT 59601
sslanger@jmgm.com

For electronic service only:
jbell@jmgm.com

Laura Rennick Andersen
MT Department of Environmental Quality
1520 E. 6th Avenue
PO Box 200901
Helena, MT 59620-0901
Landersen3@mt.gov

Human Resource Council, District XI and Natural Resources Defense Council

Charles E. Magraw
501 8th Avenue
Helena, MT 59601
c.magraw@bresnan.net

For electronic service only:
alevin@nrdc.org

Dr. Thomas Power
920 Evans
Missoula, MT 59801
tom.power@mso.umt.edu

Large Customer Group

Thorvald A. Nelson
Nikolas S. Stoffel
Austin Rueschhoff
Holland & Hart LLP
6380 South Fiddlers Green Circle, Suite 500
Greenwood Village, Colorado 80111
tnelson@hollandhart.com
nsstoffel@hollandhart.com
darueschhoff@hollandhart.com

For electronic service only:
aclee@hollandhart.com
glgargano-amari@hollandhart.com

Walmart, Inc.

Trent Justin Oram
Oram & Houghton, PLLC
38 Mountain Moose Road
Philipsburg, MT 59858
tj@oram-houghton.com

Steve W. Chriss
Director, Energy & Strategy Analysis
Walmart Inc.
2001 SE 10th Street
Bentonville, AR 72716-1594
stephen.chriss@walmart.com

NW Energy Coalition

Shiloh Hernandez
Western Environmental Law Center
103 Reeder's Alley
Helena, MT 59601
hernandez@westernlaw.org

Diego Rivas
NW Energy Coalition
1101 8th Ave
Helena, MT 59601

MEIC, Sierra Club, Vote Solar, and MREA
Jenny K. Harbine
Amanda D. Galvan
Earthjustice
313 East Main Street
Bozeman, MT 59715
jharbine@earthjustice.org
agalvan@earthjustice.org

David C. Bender
Earthjustice
3916 Nakoma Road
Madison, WI 53711
dbender@earthjustice.org

Federal Executive Agencies
Lt Col Josh Yanov
Major Andrew J. Unsicker
TSgt Ryan Moore
Ebony Payton
Nancy Anderson Sinclair
AFLOA/JACE-ULFSC
139 Barnes Drive
Tyndall AFB, FL 32403
joshua.yanov@us.af.mil
andrew.unsicker@us.af.mil
ryan.moore.5@us.af.mil
ebony.payton.ctr@us.af.mil
nancy.sinclair@us.ag.mil

Leo and Jeanne Barsanti
Mr. Russell Doty
4957 W. 6th St.
Greeley, Colorado 80111
Iwin4u1@earthlink.net

DarAnne Dunning

DarAnne Dunning

Exhibit C

Declaration of President Serena K. Wetherelt

-WOHEHIV-
The Morning Star

NORTHERN CHEYENNE TRIBE
ADMINISTRATION
P.O. BOX 128
LAME DEER, MONTANA 59043
(406) 477-6284
FAX (406) 477-6210

-WOHEHIV-
The Morning Star

August 28, 2023

Will Rosquist
Administrator, Regulatory Division
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601

Via Reddi.mt.gov and email to pschelp@mt.gov

RE: Docket No. 2022.11.102 - NorthWestern Energy 2023 Integrated Resource Plan
Comments of the Northern Cheyenne Tribe

Dear Mr. Rosquist:

The Northern Cheyenne Tribe submits these comments on NorthWestern Energy's 2023 Integrated Resource Plan to highlight the significant opportunity for cost-effective investments in reliable clean energy development on Tribal land. The Northern Cheyenne Tribe has determined that responsible development of the Northern Cheyenne Tribe's renewable energy resources can provide for economic development of such resources in a manner that maximizes the benefits to the Tribe and is consistent with the Tribe's traditional, cultural, and environmental values. And while clean energy development on the Reservation benefits the Tribe and its members, investment by NorthWestern Energy in such development would additionally provide economic opportunities to the communities near the Reservation, as well as extraordinary benefit to the utility's Montana electric customers. At the same time, NorthWestern's plan to expand its reliance on Colstrip power would harm the Tribe without providing corresponding economic and environmental benefits.

The Tribe asks the Commission to require NorthWestern to modify its plan to ensure that clean-energy resources developed on the Northern Cheyenne Reservation are given appropriate consideration.

<u>Background</u>

The Northern Cheyenne Tribe is a federally recognized Tribe headquartered on the 440,000-acre Northern Cheyenne Indian Reservation in present-day southeastern Montana, approximately twenty miles from Colstrip, Montana and the Colstrip coal-fired power plant. In addition to the power plant, the Reservation is near to the Rosebud and Spring Creek coal mines, as well as the Decker coal mine, which closed in 2021 due to declining demand for coal. Approximately 5,000 Tribal members live on the reservation, many of whom are employed or supported by family members who are employed by the power plant or area coal mines.

Despite the employment of some Tribal members in coal energy projects, the coal industry has not brought economic prosperity to the Tribe. The ongoing need for Tribal economic development is now combined with the reality of declining employment of Tribal members in coal industries as demand across the country has decreased.

Beginning in 2016, the Northern Cheyenne Tribe has prioritized pursuing sustainable energy development as an important opportunity to build revenues to fund Reservation-wide weatherization and energy assistance as well as workforce training programs. Building on a long history of environmental protection, interest in clean energy sources, and efforts to preserve the Cheyenne traditional way of life, the Tribe launched a sustainable energy development initiative to promote a resilient and diversified new "green energy" economy. To further these efforts, in 2017, the Tribe created a full-time Renewable Energy Manager staff position and the Sustainable Energy Committee—a subcommittee of the Tribal Council dedicated to evaluating and pursuing renewable energy development.

The Tribe is currently focused on the commercial development of renewable energy as a key building block for a sustainable energy future. The Northern Cheyenne Reservation is well-suited for small and large-scale renewable energy development because it possesses excellent sustainable energy resources, almost all of the land is held in trust for the Tribe and its members, and the Reservation is located near a major energy system in Colstrip through which power can be transmitted to power purchasers such as large utilities and commercial entities.

To facilitate these efforts, Tribe is preparing a Request for Proposals ("RFP") for renewable energy development on the Reservation to be issued shortly. Additionally, the Tribal Council, staff and contractors engaged in a process to identify areas of the Northern Cheyenne Reservation suitable and preferred for renewable energy development, albeit not necessarily the exclusive areas for such development. These efforts demonstrate the realistic prospect that Tribal clean energy projects will be able to deliver significant energy and capacity to NorthWestern and its customers in the near future.

The Tribe has consulted with numerous stakeholders, including the U.S. Department of Energy (DOE) Office of Indian Energy, National Renewable Energy Laboratory, Western Area Power Administration, Basin Electric, regional utilities, and Tongue River Electric Cooperative. However, to date, NorthWestern Energy has not meaningfully engaged with the Tribe to discuss potential future investment in Tribal energy resources.

<u>The IRP Does Not Address Significant Economic and Technological Benefits of Renewable Energy Development on the Northern Cheyenne Reservation.</u>

NorthWestern's IRP discounts clean energy resources as significant contributors to the utility's overall energy needs without accounting for the substantial economic and technological and benefits of purchasing clean energy generated on the Northern Cheyenne Reservation.[1]

First, the increasing affordability of wind, solar, and storage resources is enhanced by developing such resources on the Northern Cheyenne Reservation. NorthWestern's analysis did not account for the bonuses for development within an energy community and on Tribal land. Under the Inflation Reduction Act, the Northern Cheyenne Reservation is an energy community because it is within an area that has historically been at the forefront of fossil-fuel energy production.[2] Therefore projects located on the Reservation qualify for a 10 percent increase of both the Investment Tax Credit (ITC) and the Production Tax Credit (PTC).[3] And the Inflation Reduction Act further increases the ITC by 10 percentage points for projects located on Indian land.[4] A project located on the Northern Cheyenne Reservation would be eligible for both bonus credits, increasing the incentive by 20 percentage points above the standard 30 percent credit. This could significantly reduce the cost of battery storage and clean energy generating resources available to NorthWestern.[5] Furthermore, development may be streamlined on the Reservation because the Tribe has approved leasing and environmental review regulations under Tribal law.

Second, because of the Reservation's proximity to the Colstrip coal plant, clean energy resources located on the Reservation could readily use available capacity on the Colstrip Transmission System. As explained in the analysis provided by Michael Goggin, interconnection of a diverse mix of wind, solar, and storage resources to the Colstrip Transmission System could reduce or eliminate the need for NorthWestern to invest $20-30 million for the installation of reactive power devices to regulate voltage on the system.

The Tribe requests that the Commission require NorthWestern to properly account for these economic and technological advantages of purchasing clean energy from on-Reservation solar, wind, and storage resources. All told, these benefits would provide substantial benefits to NorthWestern and its customers.

---

[1] *E.g.* IRP at 23 ("The technologies needed to reach this [100% clean energy] goal sooner are not currently available in a manner that is cost effective for our company or our customers.").

[2] Rosebud and Big Horn Counties, in which the Northern Cheyenne Reservation is located, are "Energy Communities" as defined by the Inflation Reduction Act. *See* https://www.irs.gov/pub/irs-drop/n-23-29-appendix-c.pdf

[3] Public Law 117–169, 136 Stat. 1921, §§ 13101, 13102, 13701, 13702 (Aug. 16, 2022)

[4] *Id.* § 13702 (Aug. 16, 2022) (providing 10 percent in additional credits for facilities located in low-income communities or on Indian land).

[5] Moreover, as described in the memorandum prepared by Michael Goggin, the IRP significantly overstates the typical cost of wind and solar resources and understates the value of the general PTC for both wind and solar, which could reduce capital costs far more than the 30 percent that NorthWestern assumed. *See also* IRP Volume 1, at 63 (explaining that the PTC is more valuable than the 30% ITC for solar resources).

<u>The IRP Does Not Address Equitable Distribution of the Costs and Benefits of Energy Production</u>

NorthWestern should be required to revise its IRP to address how the company will ensure that the environmental and economic costs and benefits of energy production are equitably distributed, where costs have fallen disproportionately on the Northern Cheyenne Tribe and its members. Under the pre-2023 planning rules that NorthWestern is applying in this planning process, least-cost resource plans must, among other things, "minimize the environmental and other external costs not incorporated into the formal cost analysis" and "distribute costs and benefits in an equitable manner." ARM 38.5.2007(1)(c), (e) (2022). NorthWestern's draft IRP does not minimize the environmental and external costs and, importantly, does not identify plans to ensure that the costs and benefits are equitably distributed to the Northern Cheyenne Tribal community.

The Northern Cheyenne Tribe bears disproportionate harm from NorthWestern's continued reliance on coal-powered electricity generation. The Northern Cheyenne Reservation is twenty miles from the Colstrip coal-fired power plant—partially owned by NorthWestern Energy—and its associated coal mine. Since the Colstrip plant was first proposed, the Tribe has taken steps to protect its people from the harmful effects of air pollution from the plant. For example, concerned about the proposed construction of Colstrip Units 3 and 4, in 1976 the Tribe proposed to redesignate the Reservation as a Class I airshed under the Clean Air Act. After EPA approved the Tribe's proposal in 1977, the Tribe exercised its authority to require additional air pollution controls on the new Colstrip units. However, now NorthWestern Energy is opposing new federal rules that would limit the plant's emissions of hazardous air pollutants—pollution that impairs brain development, increases cancer risks, and contributes to other chronic and acute health disorders.[6] Because of the proximity of the Northern Cheyenne Tribal members to the Colstrip plant—living both on the Reservation and in the nearby community of Colstrip, where many Tribal members are employed—they are disproportionately impacted by exposure to hazardous air pollutants. If NorthWestern is going to continue relying on Colstrip, it must stop resisting the installation of the same air pollution controls that other plants across the country have already installed to protect local communities from toxic emissions.

Coal mining at the Rosebud strip mine also harms our Tribal community. Air pollution from mine activities impacts our Class I airshed. Mine runoff impairs water quality. Mining destroys habitat for sensitive species, including burrowing owls, prairie dogs, prairie chicken, and sage grouse. And even when coal mines use the best reclamation practices to restore the land, mining has caused long-term harm to our environment.

In addition to these health and environmental impacts, the power plant and mine bring new people to the Reservation, along with drugs, human trafficking, and other crime. These challenges disrupt our culture and strain Tribal infrastructure, schools, and law enforcement and

---

[6] *See* NorthWestern Corporation Comments re: Proposal on National Emissions Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (June 23, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2018-0794-5980/attachment_1.pdf.

fire-fighting personnel and equipment. At the same time, the Tribe has not seen significant economic benefit from our neighboring industries.

NorthWestern Energy proposes in its IRP to increase its reliance on Colstrip into the future, extending the burden on the Tribe, but the company has not proposed to mitigate these harms or generate any benefits owed to the Tribe. In addition to reducing or eliminating significant pollution from Colstrip and the Rosebud Mine, NorthWestern must consider opportunities to generate economic and environmental benefits to the Tribe through purchases of clean energy generated on the Northern Cheyenne Reservation.

Conclusion

NorthWestern Energy has an opportunity to invest in Tribal clean energy projects that would provide affordable energy and capacity for NorthWestern customers and more equitably distribute the costs and benefits of its energy system. The Commission should require NorthWestern to revise its IRP to fully consider this opportunity.

Sincerely,

Serena K. Wetherelt

Serena K. Wetherelt
President