APPENDIX

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APPENDIX A

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

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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

42 U.S.C.A. § 7412

§ 7412. Hazardous air pollutants

Effective: August 5, 1999
Currentness

(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. 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

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 (1-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 $R\text{-}(OCH_2CH_2)_n\text{-}OR'$ 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: $R\text{-}(OCH_2CH)_n\text{-}OH$. 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 [1] 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 establish 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 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) 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, the Federal Insecticide, Fungicide and Rodenticide Act and the Resource Conservation and Recovery Act) 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 and drinking water standards established pursuant to the Safe Drinking Water Act; 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 or listed pursuant to section 320(a)(2)(B) of such Act 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 or water quality standards pursuant to the Federal Water Pollution Control Act 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 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, 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 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 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, 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, 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[6] Act of 1986, 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.

(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 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) [4] 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; [7]

(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 [8] 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; [7]

(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. 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.

(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 subparagraph (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 (G) [5] 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 environment. 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 stationary 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, sections 3007, 3008, 3013, and 7003 of the Solid Waste Disposal Act, sections 1445 and 1431 of the Safe Drinking Water Act, sections 5 and 7 of the Toxic Substances Control Act, 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.

CREDIT(S)

(July 14, 1955, c. 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.)

Footnotes

1 So in original. Probably should be "effects".

2 So in original.

3 So in original. Probably should be "section".

4 So in original. Probably should be paragraph "(7)(B)".

5 So in original. Probably should be "subparagraph".

6 So in original. Probably should be "Right-To-Know".

7 So in original. The word “or” probably should appear.

8 So in original. The word “Administrator” probably should be ‘‘Secretary’’.

9 So in original. Probably should be “(i)(II)”.

42 U.S.C.A. § 7412, 42 USCA § 7412
Current through P.L. 118-70. Some statute sections may be more current, see credits for details.

End of Document

APPENDIX C

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

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

RIN 2060–AV53

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

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

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

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

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

SUPPLEMENTARY INFORMATION:

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

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

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

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

I. General Information

A. Executive Summary

1. Background and Purpose of the Regulatory Action

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

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

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

2. Summary of Major Provisions of the Regulatory Action

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

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

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

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

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

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

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

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

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

3. Costs and Benefits

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

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

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

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

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

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

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

[a] Values rounded to two significant figures.

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

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

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

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

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

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

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

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

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

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

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

B. Does this action apply to me?

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

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

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

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

D. Judicial Review and Administrative Reconsideration

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

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

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

II. Background

A. What is the statutory authority for this action?

1. Statutory Language

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

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

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

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

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

2. Statutory Structure and Legislative History

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Summary of the 2020 Residual Risk Review

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

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

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

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

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

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

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

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D. Summary of the 2020 Technology Review

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

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

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

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

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

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

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

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

III. What is included in this final rule?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[11] 77 FR 9406.

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

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

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

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

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

1. Proposed Changes to the Filterable PM Standard

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

2. Proposed Changes to the Requirements for Compliance Demonstration

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

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

1. Filterable PM Emission Standard

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

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

2. Compliance Demonstration Options

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

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

1. Comments on the Filterable PM Emission Standard

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[41] See 88 FR 24872.

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

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

1. Rationale for the Final Filterable PM Emission Standard

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Rationale for the Final Compliance Demonstration Options

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Mercury Content of Lignite

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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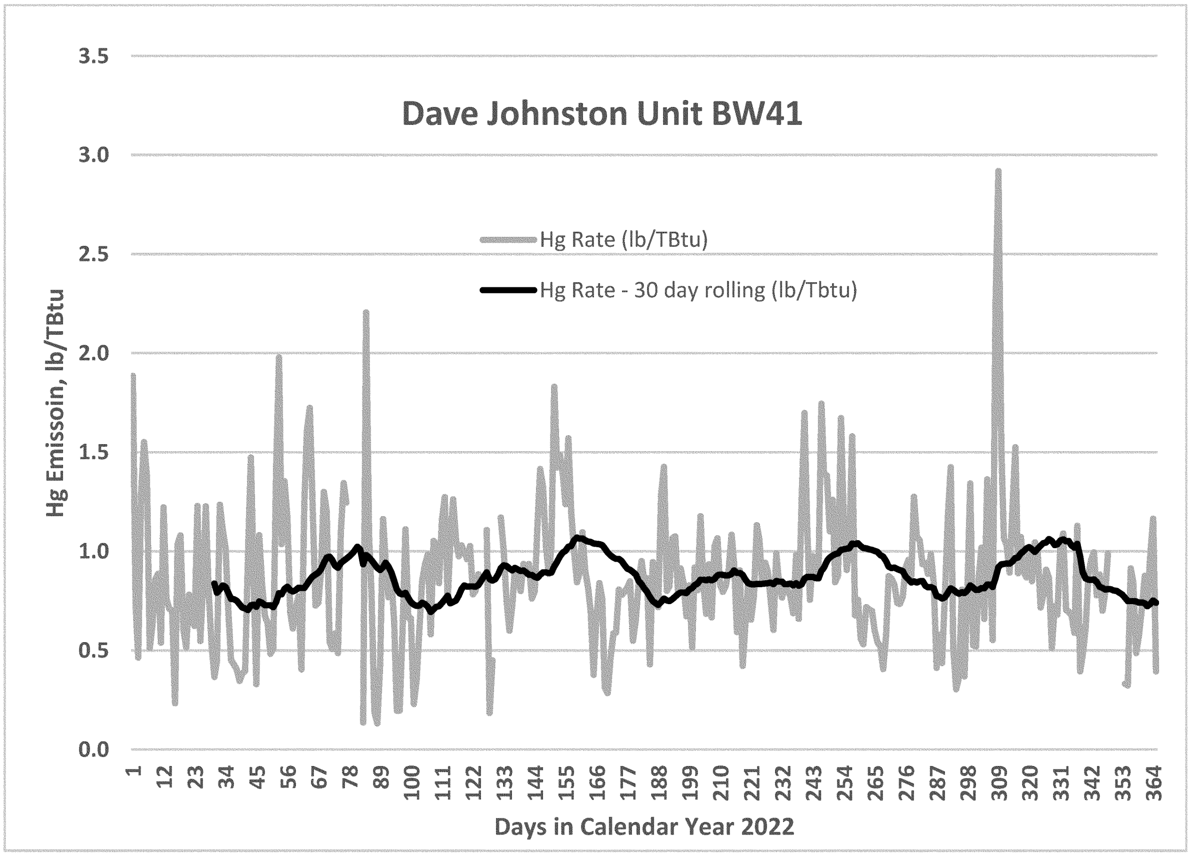

Figure 1. 2022 Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu)

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

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

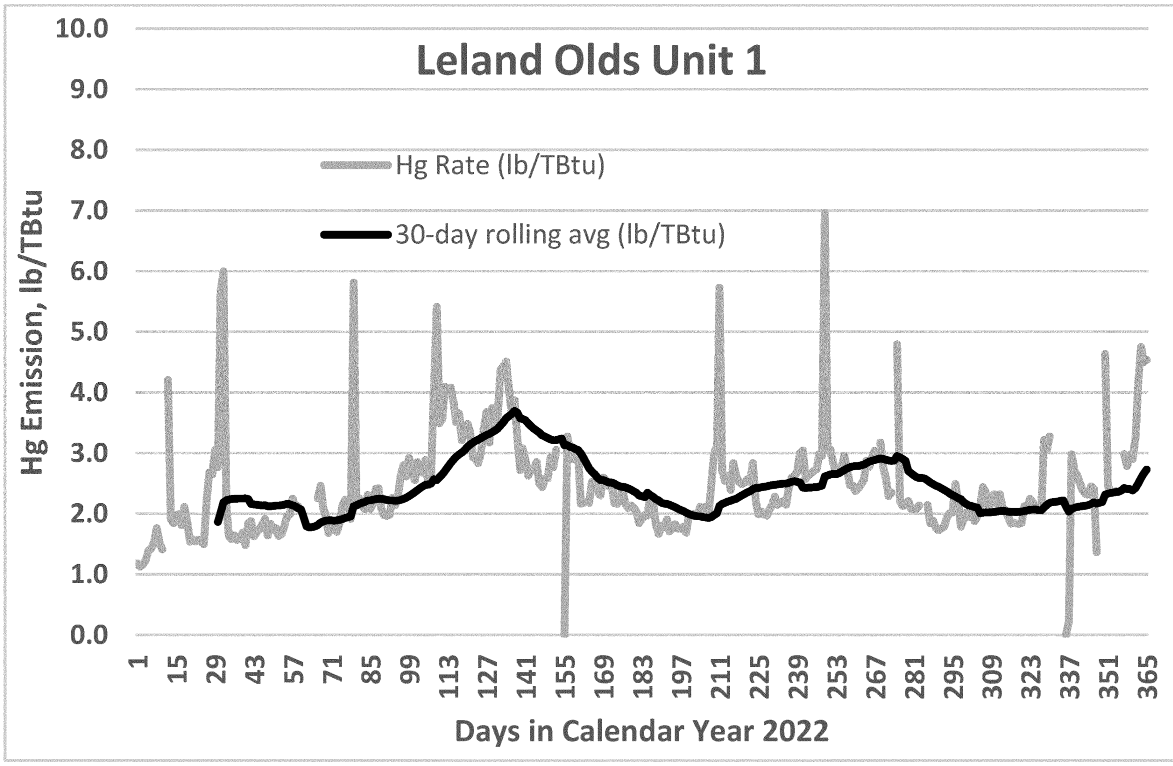

Figure 2. Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu) from Leland Olds Unit 1, lignite-fired EGU in North Dakota.

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

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

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

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

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

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

3. The Impact of SO_3 on Hg Control

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. Cost Considerations for the More Stringent Hg Emission Standard

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. What are the affected facilities?

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

B. What are the air quality impacts?

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

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

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

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

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

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

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

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

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

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

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

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

C. What are the cost impacts?

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

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

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

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

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

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

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

D. What are the economic impacts?

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

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

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

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

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

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

E. What are the benefits?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

F. What analysis of environmental justice did we conduct?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

X. Statutory and Executive Order Reviews

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. Paperwork Reduction Act (PRA)

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

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

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

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

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

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

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

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

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

C. Regulatory Flexibility Act (RFA)

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

D. Unfunded Mandates Reform Act (UMRA)

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

E. Executive Order 13132: Federalism

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

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

This action does not have tribal implications as specified in Executive

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

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

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

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

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

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

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

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

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

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

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

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

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

K. Congressional Review Act (CRA)

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

List of Subjects in 40 CFR Part 63

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

Michael S. Regan,

Administrator.

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

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

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

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

Subpart A—General Provisions

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

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

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

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

(a) * * *

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

* * * * *

■ 4. Amend § 63.10000 by:

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

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

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

■ d. Revising paragraph (c)(1)(iv);

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

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

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

■ h. Revising paragraph (m) introductory text.

The revisions and additions read as follows:

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

* * * * *

(c) * * *

(1) * * *

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

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

* * * * *

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

* * * * *

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

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

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

* * * * *

(2) * * *

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

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

(d) * * *

(5) * * *

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

* * * * *

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

* * * * *

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

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

(a) * * *

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

* * * * *

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

* * * * *

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

* * * * *

(d) * * *

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

* * * * *

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

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

* * * * *

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

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

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

* * * * *

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

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

(a) * * *

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

* * * * *

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

* * * * *

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

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

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

* * * * *

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

* * * * *

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

* * * * *

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

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

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

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

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

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

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

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

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

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

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

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

* * * * *

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

* * * * *

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

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

* * * * *

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

* * * * *

(g) * * *

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

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

* * * * *

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

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

* * * * *

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

* * * * *

(3) * * *

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

* * * * *

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

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

* * * * *

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

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

Where:

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

* * * * *

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

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

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

(a) * * *

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

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

* * * * *

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

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

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

* * * * *

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

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

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

* * * * *

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

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

* * * * *

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

§ 63.10031 What reports must I submit and when?

(a) * * *

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

(c) * * *

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

* * * * *

(f) * * *

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

* * * * *

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

* * * * *

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

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

§ 63.10032 What records must I keep?

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

* * * * *

(f) * * *

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

* * * * *

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

§ 63.10042 What definitions apply to this subpart?

* * * * *

Startup means:

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

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

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

* * * * *

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] Gross output.

[3] Incorporated by reference, *see* § 63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

		emissions concentrations	appendix A to part 63 of this chapter or ASTM D6348-03 Reapproved 2010[3] with
			(1) the following conditions when using ASTM D6348-03 Reapproved 2010:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03 Reapproved 2010, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Reapproved 2010 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 Reapproved 2010 test data to be acceptable for a target analyte, %R must be 70% ≥R ≤130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\ 100$
			(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)).

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

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

[3] Incorporated by reference, see § 63.14.

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

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

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

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

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

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

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

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

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

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

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

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

You must submit the following reports . . .

For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.

8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit), according to 40 CFR 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.

The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.

Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g).

If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90-group boiler operating day WAERs for the averaging group.

The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.

9. The semiannual compliance reports described in 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 63.10031(b).

The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.

10. Notifications of compliance status, in PDF files, according to 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.

11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.

These reports are due no later than 60 days after the end of each calendar quarter.

12. Quarterly reports, in PDF files, that include the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in 40 CFR 63.10042 (see 40 CFR 63.10031(i)). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.

These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under 40 CFR 63.10031(g).

13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 63.10031(j).

If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS Client Tool to submit the report, in a PDF file, no later than 60 days after that date.

For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.

For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.

14. Quarterly reports that include the QA/QC activities for your PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit) or approved HAP metals CMS (as applicable), in PDF files, according to 40 CFR 63.10031(k).

The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.

These reports are due no later than 60 days after the end of each calendar quarter.

■ 26. In appendix C to subpart UUUUU:
■ a. Revise sections 1.2, 1.3, 4.1, and 4.1.1.
■ b. Add sections 4.1.1.1 and 4.2.3.
■ c. Revise sections 5.1.1, 5.1.4, and the section heading for section 6.

The revisions and additions read as follows:

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

1. General Provisions

* * * * *

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

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

* * * * *

4. Certification and Recertification Requirements

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

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

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

* * * * *

4.2 Recertification.

* * * * *

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

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

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

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

* * * * *

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

* * * * *

6. Data Reduction and Calculations

* * * * *

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

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

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

* * * * *

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APPENDIX D

DECLARATION OF CHRISTOPHER D. FRIEZ

I, Christopher D. Friez, declare as follows:

1. My name is Christopher D. Friez, and I am the Vice President-Land, Associate General Counsel and Assistant Secretary of NACCO Natural Resources Corporation ("NACCO NR").

2. NACCO NR, a subsidiary of NACCO Industries, Inc., through its subsidiary North American Coal, LLC, mines and markets lignite coal primarily as fuel for power generation and provides selected value-added mining services for other natural resources companies. Its corporate headquarters is located in Plano, Texas near Dallas. NACCO NR operates surface lignite coal mines in North Dakota, Mississippi, and Louisiana.

3. NACCO NR is one of the United States' largest miners of lignite coal and among the largest coal producers in the country, producing approximately 23.9 million tons of lignite in 2023.

4. Because lignite has a higher moisture content and a lower heat content than other types of coal, and therefore cannot be transported long distances in a cost-effective manner, most lignite is sold to power plants adjacent or near to the producing mine. If a power plant served by a lignite mine closes, I am not aware of any reasonably viable new market opportunities for the lignite coal.

5. EPA's MATS rule ("MATS") will cause immediate, irreparable injury to NACCO NR, its workers, and the communities in which it mines coal in several ways. According to modeling analysis conducted by the North Dakota Transmission Authority ("NDTA"), dated April 3, 2024, a true and correct copy of which is attached as Attachment A, the changes required by MATS are likely not technologically feasible for lignite-based power generation facilities. The MATS rule eliminates the "units designed for low rank virgin

coal" subcategory established for lignite-powered facilities by causing these facilities to comply with the same mercury emission limitation that currently apply to electric generating units combusting bituminous and subbituminous coals. Numerous comments in the administrative record provide that the new emission standards are not technologically feasible and will impose crippling compliance costs that may require facility retirement. Even if compliance is technologically feasible, the added cost to comply, and unknown long term operational issues caused by the increased use of materials needed to comply, may cause plant retirements and mine closures. The EPA itself indicates, within the MATS rule, that the following plants, among others, will potentially be impacted by filterable particulate matter (fPM) and the mercury standard: Red Hills Generating Facility (MS; lignite); Antelope Valley Station (ND; lignite); Coal Creek Station (ND; lignite); Coyote Station (ND; lignite); Leland Olds (ND; lignite); and Spiritwood Station (ND; lignite). NACCO NR sells nearly all of its lignite coal production to these facilities. The retirement of these facilities would cause NACCO NR to close the coal mines which currently supply these facilities, resulting in the write off of tens of millions of dollars of investment by NACCO NR. These closures would result in hundreds of millions of dollars of stranded investment at these facilities and mines, much of which would likely be passed through to North Dakota and Minnesota ratepayers, cooperative members, and small municipalities. The closure of the Red Hills Mine would result in the loss of over $50 million of direct investment made by NACCO NR to date. In addition, early closure of these plants would result in the loss of over a thousand jobs and the loss of revenue which NACCO NR is contracted to receive well into the future. NACCO NR believes that all of these injuries are preventable if the court stays and ultimately overturns the rule.

North Dakota—Coyote Creek Mine

6. Through a wholly-owned subsidiary, Coyote Creek Mining Company, L.L.C. ("CCMC"), NACCO NR developed the Coyote Creek Mine in Mercer County, North Dakota, located about 70 miles northwest of Bismarck. The Coyote Creek Mine began making lignite deliveries to the 427-megawatt (MW) Coyote Station in 2016.

7. If Coyote Station cannot meet the requirements of the MATS rule, it will be required to close. The purpose of the Coyote Creek Mine is to support, and to provide a fuel source for, Coyote Station. Thus, if Coyote Station closes, Coyote Creek Mine would close as well. Mine closure would result in a layoff of the 90-person workforce, CCMC would go out of business, and the local community and the State of North Dakota would be deprived of the valuable attendant benefits and taxes and royalties described below in paragraphs 13 and 14.

8. To develop the mine and comply with its contractual obligations, CCMC permitted an area large enough to supply coal for the 25-year life of the contract with Coyote Station. CCMC spent over $6 million to permit the acreage needed for 25 years. If the power plant and mine must close in 2027, less than half of the acreage permitted will have been mined and CCMC will lose over $3 million in permitting costs spent to permit lands that will never be mined. In addition, $30 million of mine development costs are being amortized over the life of the mine. If that life is cut in half due to implementation of the MATS rule, another $15 million in such costs are lost.

9. In addition to permitting and mine development costs, CCMC incurred equipment costs of around $80 million to support mine startup and operation through the life of the mine. Again, these costs are being amortized over the life of the mine, and if the mine is forced to close early, nearly $40 million of those costs are lost because full amortization cannot

be realized. And the equipment will likely have a very low resale value because of the closure of other mines at the same time. Finally, if Coyote Station shuts down and the mine closes in 2027, the contractual arrangement between CCMC and the power plant owners requires CCMC to purchase the dragline and rolling stock for approximately $30 million, due to the early closure of the mine.

10. Due to the cost-plus nature of the contract under which CCMC supplies fuel to Coyote Station, many of CCMC's costs and obligations are passed through to the public utilities that jointly own Coyote Station—Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Company, and NorthWestern Corporation. In the end, the utilities, and more specifically their ratepayers and members, will pay these costs. In return, the ratepayers and members to whom the costs of Coyote Station are passed on will not have received the benefit of the low-cost and reliable power that otherwise would be delivered by Coyote Station. Their stranded investment in the Coyote Creek Mine will be lost.

North Dakota—Falkirk Mine

11. NACCO NR, through its wholly-owned subsidiary, The Falkirk Mining Company ("Falkirk"), operates the Falkirk Mine near Underwood, North Dakota, about 50 miles north of Bismarck. The Falkirk Mine annually produces between 7 million and 9 million tons of lignite for Coal Creek Station, a two-unit 1100-megawatt power plant owned by Rainbow Energy Center.
12. Coal Creek Station is impacted by the MATS rule.
13. A layoff at Falkirk Mine will be acute on numerous levels. According to an economic report prepared by North Dakota State University, a true and correct copy of which is

attached as Attachment B, in 2021, the latest year for which actual data is currently available, "The combination of coal mining, coal conversion, coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,300 direct jobs in North Dakota in 2021." "The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income." For the five hundred plus employees that stand to lose their jobs if Coal Creek Station closes, their lives, and their families' lives, may be drastically impacted.

14. Also, a shutdown would have a substantial impact across several counties and cities in North Dakota. Like all mining companies, Falkirk pays a coal severance tax of 37.5 cents on each ton of lignite mined. In 2023, Falkirk paid approximately $2,500,000 in coal severance taxes. NACCO NR's neighboring Freedom Mine paid approximately $4,500,000 in coal severance taxes. Under North Dakota law, 30% of revenue from the 37.5 cent tax is used to fund a Constitutional Trust Fund administered by the Board of University and School Lands. The other 70% is shared among the coal producing counties in the State, which is further apportioned as follows: 40% to the county general fund; 30% to the cities within the county, and 30% to the school districts. Absent a stay of the MATS rule, if these mines are forced to shut down, this will impact education, law enforcement, and social services throughout the State.

15. Even if the parties prevail in litigation efforts and the MATS rule does not ultimately go into effect, the MATS rule is already immediately impacting the operation of the mine to the detriment of the local community. At the Falkirk Mine, hiring decisions must be made with a long term vision in mind, and the decision to fill open positions or hire for new positions cannot be made with the current uncertainty the MATS rule creates. In addition, the uncertainty created by the MATS rule makes it difficult to attract and retain employees

who know they may not have a job in a few years. These difficulties are real and locations like the Falkirk Mine are experiencing them right now and will continue to experience them during the litigation of the MATS rule if a stay is not granted.

16. Decisions regarding large capital expenditures for equipment must be made years in advance due to the amount of time it takes to finance, acquire, transport, assemble and test equipment. A decision must be made now as to whether to acquire an additional dragline for the Falkirk Mine to meet customer demands and contractual obligations. A used dragline would need to be acquired now—at a cost of approximately $30 million—so the dragline can be purchased, transported, reconstructed and placed into service by late 2026 to meet these customer demands and contractual obligations. Due to their enormous size and complexity, it takes years for a used dragline to become operational at a new location. Draglines weigh millions of pounds and must be disassembled for transport (by rail and truck) to their new location. The parts and equipment constituting the dragline are transported in dozens of modular units to the new location. Upon arrival, the equipment is refurbished, re-assembled, erected, and tested. This work is done by private contractors, including truckers, welders, electricians, mechanical and electrical engineers, and software programmers.

17. Because of this extensive and time-consuming process, Falkirk must make a decision acquire to the $30 million dragline now, in order for the dragline to become operational by late 2026 to meet customer demand. If Falkirk makes this necessary decision and then is obligated to close the mine in 2027, it would lose almost all of its substantial investment in this piece of equipment, which will be worth only scrap value if the mine is shut down. Given the lead time required and the uncertainty created by the MATS rule, it is difficult to make an informed decision on such a large capital expenditure.

<u>North Dakota – Coteau Freedom Mine</u>

18. NACCO NR, through its wholly-owned subsidiary, The Coteau Properties Company ("Coteau"), operates the Freedom Mine near Beulah, North Dakota, about 75 miles northwest of Bismarck. The Freedom Mine annually produces between 12 million and 14 million tons of lignite for Antelope Valley Station ("AVS"), a two-unit 900-megawatt power plant, Leland Olds Station ("LOS"), a 660-megawatt power plant, and Dakota Gasification Company ("DGC"), a Synfuels plant, all owned by Basin Electric Power Cooperative.
19. AVS and LOS are both impacted by the MATS rule.
20. Similar to Falkirk, a layoff at Freedom Mine would be devastating to the local community. The combination of over 400 high paying jobs at the Freedom Mine alone, along with approximately 600 more at the combined facilities of AVS, LOS, and DGC are the backbone of a 100 mile radius of families' livelihoods and economic activity for central North Dakota, including the neighboring towns of Beulah and Hazen. Without the employment provided by these facilities, the towns of Beulah and Hazen could vanish, along with any economic activity in the region.
21. A shut down or curtailment of coal usage at AVS or LOS also affect the economics and operating costs of DGC. DGC enjoys a lower price for its lignite coal input based upon sharing in the volume of coal needed to operate AVS and LOS. Because of economies of scale and shared costs over a larger number of tons, if AVS and LOS are shut down, the coal costs for DGC increase exponentially, causing the economics of that facility to be strained as well.

22. NACCO NR, at its Freedom Mine, currently has about $130 million worth of property, plant, and equipment which would require accelerated depreciation if the mine is closed early because of the MATS rule. In addition to that, there is another $70 million in lease depreciation that would be unrealized, along with approximately $37 million in warehouse inventory that would have little to no value if the mine were closed early. Finally, a shut down of the Freedom Mine would result in a lost payroll of over $60 million annually.

23. Beyond the impacts of a shut down, the MATS rule is creating an immediate impact on the operation of the mine to the detriment of Coteau. At the Freedom Mine, as with Falkirk, decisions regarding large capital expenditures must be made years in advance due to the amount of time it takes to finance, acquire, transport, assemble and test equipment, and to determine how much and which types of equipment are necessary for different mine plans. There are numerous decisions relating to equipment purchases, repairs, mine plans and other capital requirements that must be delayed or decisions altered for short term requirements rather than long term decision-making, creating higher future costs and less efficient operations. Equipment purchases, or equipment maintenance, that are delayed pending the outcome of the MATS rule will add additional cost in the future. Additionally, Coteau is currently facing major mine plan decisions that depend on the length of time the mine will be in operation, but the uncertainty of the MATS rule (especially when coupled with the additional announced rules) causes great difficulty in making these decisions.

Mississippi

24. NACCO NR has owned and operated the Red Hills Mine near Ackerman, Mississippi, since 2002. On an annual basis, the Red Hills Mine produces approximately 2.4-2.8 million tons of lignite. Lignite from the Red Hills Mine is used as a fuel supply at the adjacent Red

Hills Generating Facility, a 440-megawatt power plant that provides electricity to the Tennessee Valley Authority.

25. Based on current projections, NACCO NR believes the Red Hills Generating Facility is particularly vulnerable to meeting the filterable particulate matter standard required by the MATS rule.

26. NACCO NR provides lignite to the Red Hills Generating Facility pursuant to a supply agreement that runs through 2032. The agreement, however, also includes two ten-year extension options that, if exercised, would extend the agreement to 2052.

27. Based on NACCO NR's geological data, there are enough proven lignite reserves in the vicinity of the Red Hills Mine to support mining until at least 2052. The most efficient way to mine the reserves would have been to shift approximately 6 miles of Mississippi Highway 9, which bisects the Red Hills Mine area in a north-south direction, about 2 miles to the east. However, because of previous regulatory uncertainty (much like the uncertainty that would result if the MATS rule is not stayed) the decision was made to cross Mississippi Highway 9 by constructing an underpass, rather than moving the highway. Similar operational decisions are made on a regular basis and, without a stay here, inefficient and shorter term decisions will be required. These decisions will collectively add up to significant and unnecessary financial harm.

28. NACCO NR currently has assets valued at over $50 million at the Red Hills Mine that will likely be lost as stranded investments if the MATS rule is implemented.

29. The effects of the MATS rule cannot be considered in a vacuum. EPA promulgated revisions to the New Source Performance Standards rule (greenhouse gas emissions requirements) on May 9, 2024 that require significant reductions in emissions from coal-fired power plants, including requirements for carbon capture and storage or co-firing on

alternative fuel sources, or shut down by January 1, 2032. Unfortunately, in addition to numerous other issues, the compliance dates for the two rules are misaligned. To comply with the fPM and/or mercury standards, power plants need to decide whether to spend the significant capital required to attempt to comply with MATS, if compliance is even possible, while at the same time weighing whether they can even operate past January 1, 2032 anyway. If facilities must presume they are required to shut down before January 1, 2032 anyway, it is unlikely they will invest capital to comply with the MATS rule.

30. Finally, absent a stay of the MATS rule and facing significant compliance costs over a very short implementation timeframe (if compliance is even technologically feasible), coupled with the effect of the other rules as mentioned above, a number of facilities are expected to elect not to install additional control equipment and emission monitors. If the rule is not stayed, facility owners may decide to shut down or curtail output rather than spend significant dollars with such an uncertain outcome, and NACCO NR will suffer tremendous immediate harm.

31. I, Christopher D. Friez, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct to the best of my knowledge.

Christopher D. Friez
NACCO Natural Resources Corporation

Dated: May 30, 2024

Attachment A

to the Declaration of Christopher D. Friez

INDUSTRIAL COMMISSION OF NORTH DAKOTA

NORTH DAKOTA TRANSMISSION AUTHORITY

Analysis of

Proposed EPA MATS Residual Risk and Technology Review and Potential Effects on Grid Reliability in North Dakota

Claire Vigesaa, Director

North Dakota Transmission Authority

April 3, 2024

Assisted by:

Isaac Orr and Mitch Rolling

Center of the American Experiment

Contents

Executive Summary

On behalf of the North Dakota Transmission Authority (NDTA), the Center of the American Experiment prepared this study to analyze the potential impacts of EPA's proposed revisions to the Mercury and Air Toxics Standards (MATS) Rule on North Dakota's power generation and power grid reliability.

Our primary finding, which is drawn substantially from the Rule's administrative record, is that the proposed changes are likely not technologically feasible for lignite-based power generation facilities, will foreseeably result in the retirement of lignite power generation units, and will negatively impact consumers of electricity in the Midcontinent Independent Systems Operator (MISO) system by reducing the reliability of the electric grid and increasing costs for ratepayers.

Our analysis builds upon grid reliability data and forecasts from the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), and it assesses what is likely to happen to grid reliability if the MATS Rule forces some or all of North Dakota's lignite power generation units to retire. We determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system even if these resources are replaced with wind, solar, battery storage, and natural gas plants. In reaching that determination, we have accepted EPA's estimates for capacity values of intermittent and thermal resources.

Moreover, building such replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Replacing these lignite facilities with new wind, solar, natural gas, and battery storage facilities would cost an additional $1.9 billion to $3.8 billion through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts. Accounting for projected increases in demand for electricity, we assess that if the MATS Rule goes into effect in the near future, by 2035, the MISO grid will experience up to an additional 73,699 megawatt hours (MWh) of unserved load, with an economic cost of up to $1.05 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Section A: North Dakota's Power Environment

North Dakota Transmission Authority (NDTA)

The North Dakota Transmission Authority (NDTA) was established in 2005 by the North Dakota Legislative Assembly at the behest of the North Dakota Industrial Commission. Its primary mandate is to facilitate the growth of transmission infrastructure in North Dakota. The Authority serves as a pivotal force in encouraging new investments in transmission by aiding in facilitation, financing, development, and acquisition of transmission assets necessary to support the expansion of both lignite and wind energy projects in the state.

Operating as a 'builder of last resort,' the NDTA intervenes when private enterprises are unable or unwilling to undertake transmission projects on their own. Its membership, as stipulated by statute, comprises the members of the North Dakota Industrial Commission, including Governor, Attorney General, and Agriculture Commissioner.

Statutory authority for the North Dakota Transmission Authority (NDTA) is enshrined in Chapter 17-05 of the North Dakota Century Code. Specifically, Section 17-05-05 N.D.C.C. outlines the powers vested in the Authority, which include:

1. Granting or loaning money.
2. Issuing revenue bonds, with an upper limit of $800 million.
3. Entering into lease-sale contracts.
4. Owning, leasing, renting, and disposing of transmission facilities.
5. Entering contracts for the construction, maintenance, and operation of transmission facilities.
6. Conducting investigations, planning, prioritizing, and proposing transmission corridors.
7. Participating in regional transmission organizations.

In both project development and legislative initiatives, the North Dakota Transmission Authority (NDTA) plays an active role in enhancing the state's energy export capabilities and expanding transmission infrastructure to meet growing demand within North Dakota. Key to its success is a deep understanding of the technical and political complexities associated with energy transmission from generation sources to end-users. The Authority conducts outreach to existing transmission system owners, operators, and potential developers to grasp the intricacies of successful transmission infrastructure development. Additionally, collaboration with state and federal officials is essential to ensure that legislation and public policies support the efficient movement of electricity generated from North Dakota's abundant energy resources to local, regional, and national markets.

As the energy landscape evolves with a greater emphasis on intermittent generation resources, transmission planning becomes increasingly intricate. Changes in the generation mix and the redistribution of generation resource locations impose strains on existing transmission networks, potentially altering flow directions within the network. A significant aspect of the Authority's responsibilities involves closely monitoring regional transmission planning efforts. This includes observing the activities of regional transmission organizations (RTOs) recognized by the Federal Energy Regulatory Commission (FERC), which oversee the efficient and reliable operation of the transmission grid. While RTOs do not own transmission assets, they facilitate non-discriminatory access to the electric grid, manage congestion, ensure reliability, and oversee planning, expansion, and interregional coordination of electric transmission.

Many North Dakota service providers are participants in the Midcontinent Independent System Operator (MISO), covering the territories of several utilities and transmission developers. Additionally, some entities are part of the Southwest Power Pool (SPP), broadening the scope of transmission planning. Together, North Dakota utilities and transmission developers contribute to a complex system overseeing the transmission of over 200,000 megawatts of electricity across 100,000 miles of transmission lines, serving homes and businesses in multiple states.

MISO and SPP also operate power markets within their respective territories, managing pricing for electricity sales and purchases. This process determines which generating units supply electricity and provide ancillary services to maintain voltage and reliability. Overall, the NDTA's involvement in regional transmission planning and coordination is crucial for ensuring the reliability, efficiency, and affordability of electricity transmission across North Dakota and beyond.

FERC-Recognized Regional Transmission Organizations and Independent System Operators

(www.ferc.gov)

Generation Adequacy, Transmission Capacity & Load Forecast Studies

The North Dakota Transmission Authority (NDTA) conducts periodic independent evaluations to assess the adequacy of transmission infrastructure in the state. In 2023, the NDTA commissioned two generation resource adequacy studies, one for the Midcontinent Independent System Operator (MISO) and another for the Southwest Power Pool (SPP). Additionally, the NDTA recently completed a generation resource adequacy study examining the impact of the EPA's proposed Mercury and Air Toxics Standards (MATS) Rule. A transmission capacity study commissioned by the NDTA is scheduled for completion in the summer of 2024.

Regular load forecast studies are also commissioned by the NDTA, with the most recent study completed in 2021. This study, conducted by Barr Engineering, provided an update to the Power Forecast 2019, projecting energy demand growth over the next 20 years. The 2021 update incorporates factors such as industries expressing interest in locating in North Dakota, abundant natural gas availability from the Bakken wells, and the potential for carbon capture and sequestration from various sources. The 2021 update and the full study can be obtained from the North Dakota Industrial Commission website: Power Forecast Study – 2021 Update, https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-annualreport-21.pdf

The Power Forecast 2021 Update projects a 10,000 GWhr increase in energy demand over the next two decades under the consensus scenario, requiring approximately 2200 to 2500 MW of additional capacity to meet demand. These projections are closely tied to industrial development forecasts and are coordinated with forecasts used by the North Dakota Pipeline Authority. These projections were highly dependent on industrial development and are premised on new federal regulations not forcing the early retirement of even more electric generation units.

Meeting this growing demand poses significant challenges for utilities responsible for providing reliable service. While there is considerable interest in increasing wind and solar generation, natural gas generation is also essential to provide stability to weather-dependent renewable sources. Importantly, load growth across the United States is driven by the electrification of transportation, heating/cooling systems, data centers, and manufacturing initiatives.

Studies consistently highlight the critical importance of maintaining existing dispatchable generation to prevent grid reliability failures. Ensuring uninterrupted power supply is paramount for national security, public safety, food supply, and overall economic stability. The NDTA's ongoing assessments and proactive planning are crucial for meeting the evolving energy needs of North Dakota while maintaining grid reliability and resilience.

The timing and implementation of resources to meet this growing demand is a significant challenge for the utilities. Importantly, electric demand growth across the United States over the next several decades is projected to be dramatic due to the electrification of transportation, home heating/conditioning, data center and artificial intelligence centers, as well as the effort to bring manufacturing back to the USA. Studies by NDTA and others all point to the critical need to keep all existing dispatchable generation online to avoid catastrophic grid reliability failures, and have been warning that the push to force the retirement of reliable, dispatchable fossil fuel generation units is occurring before it is projected there will be sufficient intermittent units in place to cover the anticipated increase in demand. And when demand for electricity exceeds the dispatchable supply, the foreseeable result will be blackouts or energy rationing.

Current North Dakota Generation Resources

Here is the current breakdown of North Dakota's generation resources:

1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW since it is intermittent. This is representative of the

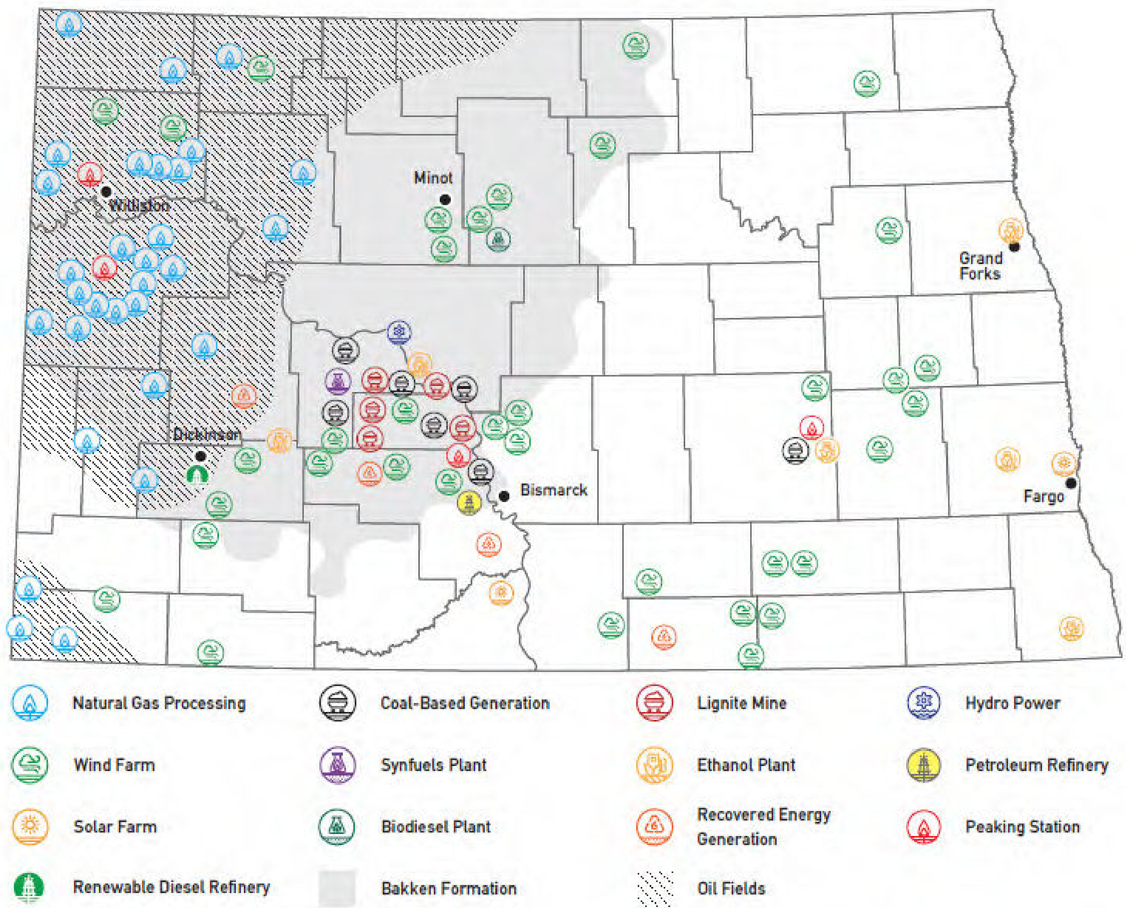
amount that is estimated to be available for the peak demand in the summer.

- Solar Generation: Although North Dakota currently lacks utility-scale solar generation facilities in operation, some projects are in the queues of regional transmission organizations like MISO and SPP, indicating potential future development in this area.

2. Thermal Coal Generation:
    - North Dakota currently operates thermal coal generation at six locations, comprising a total of 10 generating units with a combined capacity of approximately 4,048 MW.
    - The average capacity factor for these generating plants ranged from 65% to 91% in 2021, excluding the retired Heskett Station.
    - Rainbow Energy operates the Coal Creek Station and the DC transmission line that transports ND produced energy to the Minneapolis region. Rainbow Energy is assessing a CO2 capture project for the facility. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity on the DC line.
3. Hydro Generation:
    - North Dakota has one hydro generation site equipped with 5 units, boasting a total capacity of 614 MW.
    - However, the average capacity factor declined to approximately 43% in 2021 due to limitations imposed by water flow in the river, particularly during drought years.
4. Natural Gas Generation:
    - North Dakota operates three sites for electric generation utilizing natural gas, comprising 21 generating units with a total capacity of 596.3 MW.
    - These units include reciprocating engines and gas turbines, with variation in summer capacity influenced by the performance of gas generators in hot weather.
    - Total natural gas generation in North Dakota remained steady from 2019 through 2021, amounting to 1.445 GWhr in 2021.
5. Total Generation:
    - The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW.
    - Wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW due to its intermittent nature, down from 4,250MW of installed capacity, representing the estimated amount available during peak summer demand. However, newer installations have demonstrated slightly higher capacity for accreditation.

This comprehensive overview underscores the diverse mix of generation resources in North Dakota, with significant contributions from wind, coal, hydro, and natural gas. Continued assessment and adaptation to evolving energy needs and market dynamics are essential for ensuring a reliable and sustainable energy future for the state.

energy sites of
NORTH DAKOTA



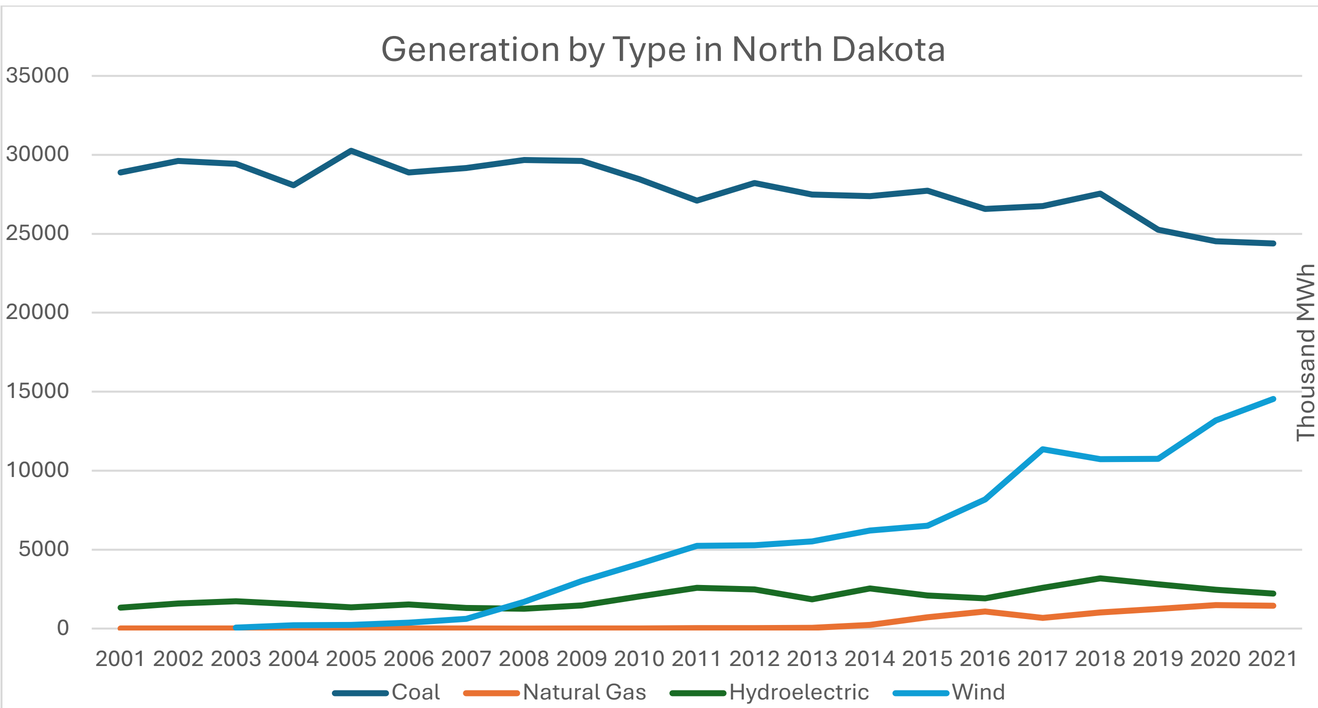
+ *Map courtesy of Bismarck State College National Energy Center of Excellence.*

Electric Generation Market & Utilization

In recent decades, North Dakota has emerged as a significant exporter of electricity, primarily fueled by the development of thermal lignite generation in the western part of the state since the 1960s. Concurrently, transmission infrastructure has been expanded to facilitate the export of electricity to markets predominantly situated to the east. Moreover, North Dakota has garnered recognition as an excellent source of wind generation, leading to additional transmission development to accommodate the transmission of this renewable energy to markets.

According to data from the Energy Information Administration, in 2020, North Dakota generated a total of 42,705 MWh of electricity from all sources, with 46% of this total being exported beyond the state's borders over two large high voltage direct current lines (HVDC), which serve load in the neighboring state of Minnesota and multiple 345kv and 230kv alternating current (AC) transmission lines serving surrounding states. Wind generation accounted for 31% of North Dakota's total electricity generation in 2020, highlighting the growing significance of renewable energy in the state's energy portfolio. Notably, industrial demand in North Dakota experienced substantial growth, expanding by nearly 11% in 2020.

While demand for electricity in markets outside of North Dakota, and in most areas within the state, has remained relatively stable in recent years, the Bakken region has witnessed notable demand growth. Over the past 16 years, total electricity generation in North Dakota has increased from 29,936 MWh to 42,705 MWh, with retail sales climbing from 10,516 MWh to 22,975 MWh. This growth is primarily attributed to the burgeoning development of the Bakken oil fields. Industrial consumption in North Dakota also witnessed a robust increase of over 11% in 2020, with power forecasts projecting a continued upward trajectory in demand.



Grid Resource Adequacy and Threats to Growth Opportunities

In 2023, both the MISO and SPP grid operators issued warnings about the adequacy of generation resources to meet peak demand situations. This highlights a growing concern that the desired pace of change towards a more sustainable energy future is outpacing the achievable pace of transformation. This concern is underscored by the stark increase in grid events necessitating the activation of emergency procedures. **For instance, prior to 2016, MISO had no instances requiring the use of emergency procedures, but since then, there have been 48 Maximum Generation events.**

Many experts in the industry project that, despite ambitious goals, realistic scenarios still foresee a substantial dependence on fossil fuel energy—potentially up to 50%—even by 2050. While efforts to decarbonize fossil fuel resources are underway, achieving complete carbon neutrality or a fully renewable energy grid by 2050 appears increasingly unlikely. The scalability and affordability of storage technology, particularly for renewable energy sources, remain significant challenges.

In response to these challenges, Governor Burgum has issued a visionary goal for North Dakota to achieve carbon neutrality in its combined energy and agriculture sectors by 2030. Governor Burgum's approach emphasizes innovation over mandates, aiming to attract industries and technologies that support this goal to the state. The initiative seeks to leverage advancements in carbon capture and sequestration technologies to retain conventional generation in North Dakota while also promoting sustainable agricultural practices and other innovative solutions, such as CO2 sequestration from ethanol production and enhanced oil recovery. These efforts demonstrate a commitment to proactive and pragmatic solutions to address the complexities of achieving carbon neutrality in the energy and agriculture sectors.

The state's vision for a decarbonized energy generation future faces significant challenges due to the individual and cumulative impact of expansive federal rulemakings. These regulations would curtail the flexibility to achieve the 2030 goal through the deployment of carbon capture and sequestration (CCS) technologies. Furthermore, they would impose financial burdens on electric cooperatives and utilities with limited resources, diverting investment away from future growth options toward retrofitting existing facilities with costly emissions technologies to comply with new federal requirements.

This regulatory burden not only impedes progress towards decarbonization but also introduces opportunity costs for utilities and cooperatives. The funds that would otherwise be allocated for future growth and innovation in clean energy solutions are instead diverted to compliance measures, hindering the state's ability to transition to a more sustainable energy future efficiently and effectively.

Ultimately, the restrictive nature of these federal rulemakings poses a significant obstacle to North Dakota's efforts to achieve its decarbonization goals and undermines the state's vision for a cleaner and more sustainable energy generation landscape. It highlights the need for a balanced approach to regulation that supports innovation and investment in carbon reduction technologies while also allowing for continued economic growth and development in the energy sector.

Grid Reliability Is Already Vulnerable

The fragility of grid reliability is already evident as warnings have been issued due to the declining ratio of dispatchable and intermittent generation supplies. This concerning trend poses significant threats to public safety, economic stability, and national security. Grid reliability is vital for ensuring continuous access to essential services, such as food production and military operations. Dispatchable reliable generation forms the backbone of grid stability, enabling the balancing of supply and demand fluctuations. Failure to address these reliability concerns will compromise critical infrastructure and expose society to substantial risks. Urgent action is required to safeguard grid reliability and mitigate the potential consequences for public safety and national security.

NERC's 2023 Reliability Risk Assessment

The North American Electric Reliability Council's 2023 Reliability Risk Assessment[1] are concerning as demonstrated in the slides below. The electrification of the US economy, data & AI center growth and the build it at home initiatives will substantially increase the demand for electricity generation and transmission.

NERC's 2023 Summer Reliability Assessment warns that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand. While there are no high-risk areas in this year's assessment, the number of areas identified as being at elevated risk has increased. The assessment finds that, while resources are adequate for normal summer peak demand, if summer temperatures spike, seven areas — the U.S. West, SPP and MISO, ERCOT, SERC Central, New England and Ontario — may face supply shortages during higher demand levels.

"Increased, rapid deployment of wind, solar and batteries have made a positive impact," said Mark Olson, NERC's manager of Reliability Assessments. "However, generator retirements continue to increase the risks associated with extreme summer temperatures, which factors into potential supply shortages in the western two-thirds of North America if summer temperatures spike."

The North American Electric Reliability Corporation (NERC) recently released its 2023 Long-Term Reliability Assessment (LTRA), which found MISO is the region most at risk of capacity shortfalls in the years spanning from 2024 to 2028 due to the retirement of thermal resources with inadequate reliable generation coming online to replace them.[2]

[1] NERC. "North American Reliability Assessment." North American Electric Reliability Corporation, May 2023, https://www.nerc.com/news/Headlines%20DL/Summer%20Reliability%20Assessment%20Announcement%20May%202023.pdf.

[2] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

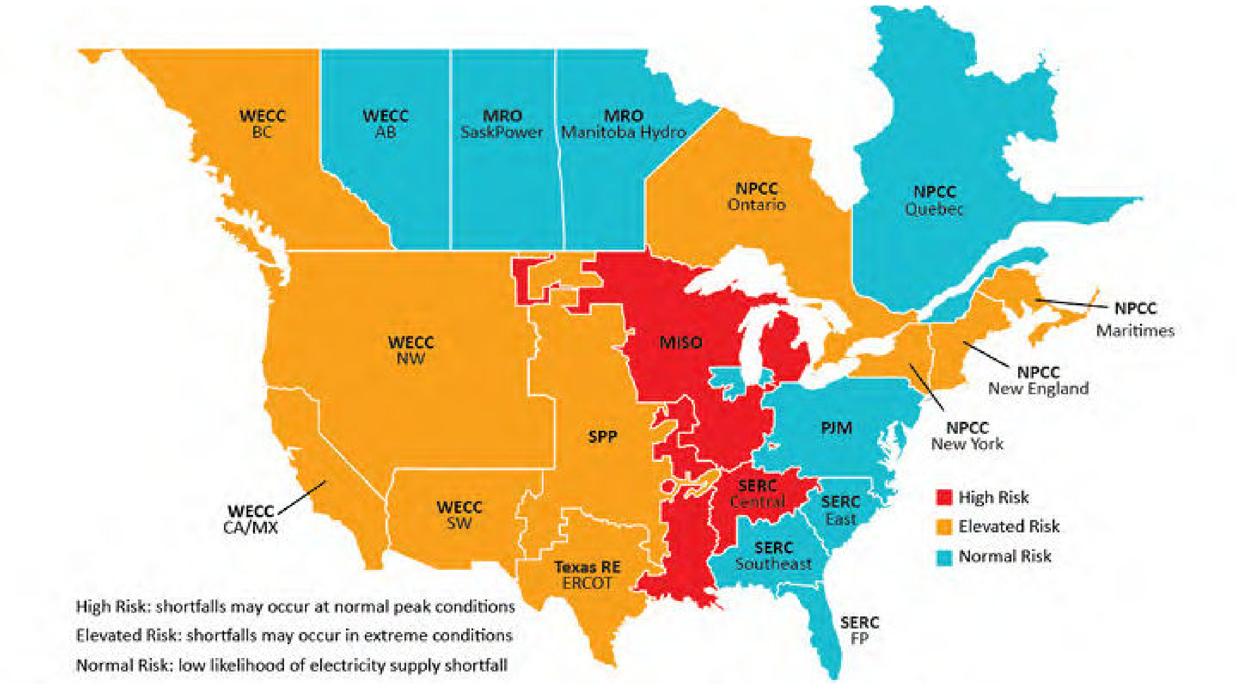


Figure 1: Risk Area Summary 2024–2028[8]

MISO is the region most at risk of rolling blackouts in the near future.

In 2028, MISO is projected to have a 4.7 GW capacity shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW, leaving MISO at risk of load shedding during normal peak conditions. This is because the new wind and solar resources that are being built have significantly lower accreditation values than the older coal, natural gas, and nuclear resources that are retiring.[3]

MISO's Response to the Reliability Imperative (2024)

On February 26, 2024, the Midcontinent Independent System Operator (MISO) released "MISO's Response to the Reliability Imperative[4]," a report which is updated periodically to reflect changing conditions in the 15-state MISO region that extends through the middle of the U.S. and into Canada. MISO's new report explains the disturbing outlook for electric reliability in its footprint unless urgent action is taken. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliability attributes.

From 2014 to 2024, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve

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[3] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[4] MISO. "MISO'S Response to the Reliability Imperative Updated February 2024." MISO, February 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

margin requirements.[5]

According to the Reliability Imperative, MISO uses an annual planning tool called the OMS-MISO Survey to compile information about new resources utilities and states plan to build and older assets they intend to retire. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time.

MISO lists U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would as a compounding reason for growing challenges to grid reliability. From the report, there is a section titled, "EPA Regulations Could Accelerate Retirements of Dispatchable Resources," which states:

> *"While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability.* ***In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.***
>
> *In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.*
>
> *MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline.* ***If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*** *The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources*."

Despite these reliability warnings issued by MISO, EPA did not consider the reliability impacts of the proposed MATS rules required emission control upgrades and additions to units. It is likely that many units that would have to incur millions of dollars to retrofit emissions controls to comply with this proposal would not do so.[6]

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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[5] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[6] Rae E. Cronmiller, "Comments on Proposed National Emission Standards for Hazardous Air Pollution: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," The National Rural Electric Cooperative Association, June 23, 2023, Attention Docket ID NO. EPA-HQ-OAR-2018-0794.

Conclusion: The Long Term Reliability of the MISO Grid is Already Precarious

As the state agency responsible for the strategic buildout and framework of electricity distribution, the North Dakota Transmission Authority (NDTA) is deeply concerned about the potential impact of federal rulemakings on the generation fleet in North Dakota and the ability to support future growth initiatives. The current strain on the electric transmission system due to load growth is already posing significant challenges to grid reliability, particularly in areas facing transmission constraints and limited access to dispatchable generation.

The escalating frequency of grid events requiring emergency procedures, such as the 48 Maximum Generation events in MISO since 2016 and the increasing number of alerts issued by SPP, over 194 alerts issued in 2022, underscores the urgency of addressing transmission congestion and bolstering reliable generation capacity. The economic growth and security of North Dakota are directly tied to the timely development of new transmission facilities in tandem with dependable dispatchable electric generation.

The impacts of grid strain extend beyond the energy sector, affecting multiple industries, ratepayers, and overall economic stability. Volatile wholesale prices and transmission congestion undermine business operations and investment confidence, hindering economic growth and prosperity. Moreover, reliable electricity supply is critical for essential services, including Department of Defense facilities, underscoring the broader implications of grid reliability issues.
Achieving a balanced generation portfolio requires careful consideration of reliability and resilience under all weather conditions, especially amidst the electrification of America and the imperative to safeguard public welfare and security.

Additionally, over 50% of the electricity generated in North Dakota is exported to neighboring states, magnifying the ripple effects of any regulations impacting dispatchable electricity generation resources. By responsibly managing the generation portfolio and prioritizing generation adequacy, North Dakota and the nation can seize significant opportunities for economic growth, innovation, and sustainable development.

Section B: The Proposed MATS Rule Will Dramatically Affect North Dakota Lignite Electric Generating Units

The revised MATS Rule includes a proposal to eliminate the "low rank coal" subcategory established for lignite-powered facilities by requiring these facilities to comply with the same mercury emission limitation that currently applies to Electric Generating Units (EGUs) combusting bituminous and subbituminous coals, which is 1.2 pounds per trillion British thermal units of heat input (lb/TBtu). EPA's proposal is a substantial lowering of the current mercury limitation for lignite fired EGUs, which is 4.0 lb/TBtu.[7,8] The proposal also includes a significant reduction in the particulate matter standard applicable to all existing units from 0.03 lb/mmBtu to 0.01 lb/mmBtu. Because North Dakota is somewhat unique to the degree in which its power generation relies upon lignite coal, the compliance costs for this Rule, while likely to substantial for coal plants all around the country, will be most acutely inflicted upon North Dakota's lignite-based power generation facilities.

Numerous comments in the administrative record, including from the regulated facilities in North Dakota and the North Dakota Department of Environmental Quality, provided EPA with notice that the new emission standards are not technologically feasible, will impose crippling compliance costs that may require facility retirement, and will result in a significant portion of the dispatchable power provided by coal-generation facilities being taken off the grid. This report will summarize some of those concerns in the section that follows, however, a full study of the technological feasibility of complying with the new emissions standards is beyond the scope of this report. For purposes of this report, we assume the regulated facilities and state regulator were forthright in their concerns about the feasibility of lignite-based facilities meeting the new standards.

The Proposed MATS Rule Eliminates the Lignite Subcategory for Mercury Emissions

Although the Proposed Rule affects all coal electrical generating utilities (EGUs), reducing the lignite emissions standards to levels of other coal ranks effectively eliminates the lignite sub-category and would have drastic consequences for North Dakota's lignite EGU industry.[9] EPA original decision to regulate separately a subcategory of lignite units was well-supported with documented information and a thorough analysis. In its comments filed in this Docket, on June 22, 2023, the North Dakota Department of Environmental Quality (hereafter DEQ) encouraged EPA to review that prior determination and reaffirm the need for a lignite subcategory and the associated emissions standards.[10]

Specifically, DEQ summarized the original MATS proposal in 2011 and final MATS rule in 2012, in which EPA presented a body of evidence in support of the lignite category. For example, the EPA wrote:

> "For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter free

[7] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[8] [8] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, (June 2, 2023) ("Cichanowicz Report").

[9] EPA characterizes lignite as "low rank virgin coal". 88 Fed. Reg. 24,854, 24,875. For this comment letter, lignite will be used in place of low rank virgin coal.

[10] David Glatt, P.E., "Comments on the Proposed Rulemaking Titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Docket ID No. EPA-HQOAR-2018-0794)," On Behalf of the North Dakota Department of Environmental Quality, June 22, 2023.

basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units.

The boiler of a coal-fired EGU designed to burn coal with that heat value is larger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories."

As explained by DEQ, EPA has not provided any scientific justification to support abandoning the lignite subcategory and requiring those facilities to comply with the emission standards applicable to other coal types. The most EPA identified in support of its proposal was a reference to information nearly 30 years old, which predated EPA's original determination.

The Proposed MATS Rule Will Not Provide Meaningful Human Health or Environmental Benefits

Section 112(f)(2) of the CAA directs EPA to assess the remaining residual public health and environmental risks posed by hazardous air pollutants (HAPs) emitted from the EGU source category.[11] Further regulation under MATS is required only if that residual risk assessment demonstrates that a tightening of the current HAP emission limitations is necessary to protect public health with an ample margin of safety or protect against adverse environmental effects.

When reviewing whether to revise the MATS Rule, EPA determined that further regulation of mercury and other HAPs would be unnecessary to address any remaining residual risk from any affected EGU within the source category. The stringent standards based on state-of-the-art control technologies that are currently imposed on coal-fired EGUs have already achieved significant reductions in HAP emissions. As EPA itself noted, the MATS rule has achieved steep reductions in HAP emission levels since 2010, including a 90 percent reduction in mercury, 96 percent reduction in acid gas HAPs, and an 81 percent reduction in non-mercury metal HAPs.[12]

Data from EPA and the U.N Global Mercury Assessment show mercury emissions from U.S. power plants are now so low they accounted for only 0.12 percent of global mercury emissions in 2022, assuming all other sources remained constant at 2018 levels.[13] These data demonstrate that

[11] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").
[12] Fact Sheet, *EPA's Proposal to Strengthen and Update the Mercury and Air Toxics Standards for Power Plants,* *https://www.epa.gov/system/files/documents/2023-04/Fact%20Sheet_MATS%20RTR%20Proposed%20Rule.pdf*
[13] United Nations, "Global Mercury Assessment 2018," UN Environment Programme, August 21, 2019, https://wedocs.unep.org/bitstream/handle/20.500.11822/27579/GMA2018.pdf?sequence=1&isAllowed=y

US mercury emissions from power plants are lower than global cremation emissions, and North Dakota coal facilities emitted 9.25 times less mercury in 2021 than global cremations in 2018.[14]

Mercury Emissions Estimates by Sector 2018 vs U.S. and N.D. Coal Plant Emissions		
Category	US Tons	Percent of Global Emissions
Artisanal and small-scale mining	921.42	37.68
Global stationary combustion of coal	517.45	21.16
Non-ferrous metals production	359.32	14.69
Cement production	256.48	10.49
Waste from products	161.63	6.61
Vinyl chlorine monomer	64.09	2.62
Biomass burning	57.05	2.33
Ferrous metals production	43.89	1.79
Chlor alkali production	16.66	0.68
Waste incineration	16.44	0.67
Oil refining	15.81	0.65
Stationary combustion of oil and gas	7.84	0.32
Cremation	4.14	0.17
US stationary combustion of coal	2.90	0.12
North Dakota coal combustion	0.46	0.018

As the above chart indicates: the annual mercury emissions from global cremations (where the mercury primarily comes from individuals with dental fillings) exceed the mercury annually emitted by all coal-fired EGUs in the United States combined, and is orders of magnitude more than the mercury emissions from all coal-fired EGUs in North Dakota.[15]

Moreover, the Administrative Record indicates EPA has performed a comprehensive and detailed risk assessment that clearly documents the negligible remaining residual risks posed by the very low amount of HAPs now being emitted by coal-fired EGUs. EPA first performed that risk assessment in 2020, which concluded that "both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of

[14] ERM Sustainability Initiative, "Benchmarking Air Emissions of the 100 Largest Power Producers in the United States," Interactive Tool, accessed February 29, 2024, https://www.sustainability.com/thinking/benchmarking-air-emissions-100-largest-us-power-producers/

[15] UN Environmental Programme. (2018). Global Mercury Report 2018, Technical Background Report to the Global Mercury Assessment. https://www.unenvironment.org/resources/publication/global-mercury-assessment-technical-background-report

acceptability" for protecting public health with an adequate margin of safety.[16] Similarly, EPA's risk assessment supports the conclusion that residual risks of HAP emissions from the EGU source category are "acceptable" for other potential public health effects, including both chronic and acute non-cancer effects.[17]

These conclusions have been confirmed by the detailed reevaluation of the 2020 risk assessment that the Agency is now completing as part of the current rule-making action. That EPA reevaluation clearly demonstrates that the 2020 risk assessment did not contain any significant methodological or factual errors that could call into question the results and conclusions reached in the 2020 risk assessment. Most notably, EPA used well-accepted approaches and methodologies for performing a residual risk analysis that adhere to the requirements of the statute and are consistent with prior residual risk assessments performed by EPA over the years for other industry sectors.[18]

The results from both residual risk assessments can lead to only one rational conclusion: the current MATS limitations provide an ample margin of safety to protect public health in accordance with CAA section 112.

The DEQ filed comments addressing these points and asking EPA to provide a better health benefit justification than the rationale currently included in the Regulatory Impacts Analysis (RIA).[19] In particular, DEQ noted that EPA cannot rely on non-HAPs' co-benefits to justify the Proposed Rule, and EPA has not identified any HAP-related benefits that would be sufficient to justify the Proposed Rule. The agency also voiced skepticism over what it called EPA' s suspect characterization of the health benefits that it identified, which is quoted below:

> While the screening analysis that EPA completed suggests that exposures associated with mercury emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers.[20]

DEQ's well-founded concern is that EPA's admission that current exposure associated with mercury is below levels of concern is directly inconsistent with, not support of, EPA's proposal for a lower standard.

DEQ commented that this theme, unfortunately, is consistent across the entire "Benefits Analysis" section of the RIA, citing another example of this inconsistency, which is quoted below:

> "Regarding the potential benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively

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[16] 88 Fed. Reg. at 24,865.
[17] *Id*. at 24,865-66.
[18] 88 Fed. Reg. at 24,865.
[19] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.
[20] *Id.* At p. 0-8.

....Overall, the uncertainty associated with modeling potential of benefits of mercury reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates-though importantly such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including methylmercury exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-mercury metal HAP were not expected to exceed acceptable levels, although we note that these emissions reductions should result in decreased exposure to HAP for individuals living near these facilities."[21]

Comments filed by the Lignite Energy Council (LEC) further emphasize the point. LEC stated that according to the risk review EPA conducted in 2020, which EPA has proposed to reaffirm, the risks from current emissions of hazardous air pollutants (HAP) emitted by coal-fired power plants are several orders of magnitude below what EPA deems sufficient to satisfy the Clean Air Act.[22] LEC points out that EPA has for decades found risks to be acceptable with an ample margin of safety if maximum individual excess cancer risks presented by any single facility is less than "100-in-1 million." In comparison, EPA's analysis of the coal- and oil-fired electric utility source category recognizes the risk it presents is now at one tenth of that acceptable level, with a maximum risk from any individual facility of "9-in-1 million."

However, even that value vastly overstates the risk associated with coal-fired power plants. The "9-in-1 million" risk level identified by EPA is only associated with a single, uncontrolled, residual oil-fired facility located in Puerto Rico.[23] What EPA's discussion of risk fails to recognize, but its analysis clearly shows, is that the highest level of risk presented by any coal-fired power plant is actually "0.3-in-1 million," more than 300 times lower than the threshold EPA deems acceptable.[24]

The level of risk presented by North Dakota lignite-powered plants is lower still. According to EPA's risk review, the maximum risks presented by any North Dakota lignite-fired power plant is "0.08-in-1 million," yet another order of magnitude lower than the highest risk from any coal-fired plant, and more than three orders of magnitude lower than EPA's "acceptable" level of risk with an "ample margin of safety."

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[21] *Id.* at pp. 4-1 - 4-2.

[22] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[23] *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, Docket ID No. EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019) ("Risk Assessment") (note that Table 2a is printed upside down in the final September 2019 version of the Residual Risk Assessment posted at www.regulations.gov, which may interfere with search commands; a searchable version of the same table is available in the December 2018 draft version, Docket ID No.). *See also* 84 Fed. Reg. at 2699 ("There are only 4 facilities in the source category with cancer risk at or above 1-in-1 million, and all of them are located in Puerto Rico.").

[24] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

The risks from North Dakota lignite are so low that they are more easily expressed, not in a million, but in a ***billion***—EPA has determined that the excess cancer risks from all North Dakota lignite plants fall between 5- and 80-in-1 billion.[25] Moreover, EPA's analysis indicates that those maximum risks are not associated with mercury.[26]

In fact, EPA's own analysis confirms the risks from North Dakota lignite-powered plants are so low they are little more than a rounding error that does not even qualify as a significant digit. In its analysis of the still low but relatively higher risk from the Puerto Rican oil-fired plants, EPA determined that one of those facilities presented a risk no greater than "1-in-1 million," even though EPA's modeling actually returned a risk level of "1.**09**-in-1 million."6 EPA discarded the extra ".09," apparently finding it too small to matter. However, that extra ".09" risk equates to "90-in-1 billion," and it is therefore higher than the ***entire*** risk identified for any North Dakota lignite plant.

The Administrative Record Indicates the Mercury Standard of 1.2 lb./TBtu is Technically Unachievable for EGUs using North Dakota Lignite Coal

The Administrative Record for the proposed rule suggests EPA made numerous critical mistakes in assuming lignite fired EGUs can achieve a 1.2 Hg/lb limit with 90% Hg removal. As detailed in the Cichanowicz Report, Section 6, EPA assumed the characteristics of lignite and subbituminous coals are similar such that the Hg removal by emission controls capabilities is similar. In this light, EPA did not consider that the high presence of sulfur trioxide (SO3) in lignite coal combustion flue gas that significantly limits the Hg emissions reduction potential of emissions controls.[27]

Similarly, as noted by LEC, EPA's proposal references data obtained via an information collection request as indicative of the level of performance achievable at North Dakota lignite facilities, but that data only reflects relatively short-term testing that does not fully capture the significant variability of lignite coals. Also, unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, all North Dakota lignite units are located at mine-mouth facilities without access to other coal types, and therefore depend entirely on the fuel extracted from the neighboring mine. As a result, changes in constituents between seams of lignite coal can result in a high level of variability in the emission rates that result from use of the coal as it is mined over time.[28]

While LEC agreed with EPA that the injection of activated carbon is the most effective means of reducing mercury emissions from lignite-powered units, LEC also criticized EPA for ignoring the well-known diminishing returns of injecting more carbon. With each marginal increase in carbon

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[25] Risk Assessment, Tbl. 2a (indicating cancer risks of 8.07e-08, 3.09e-08, 1.31e-08, 1.21e-08, and 5.12e-09 for Facility NEI IDs 380578086511, 380578086311, 380558011011, 380578086511, 380578086611 (Milton R. Young, Leland Olds, Coal Creek, Antelope Valley, and Coyote).

[26] *Id*., at Tbl. 2a (indicating the target organ of the risk associated with the plants identified in note 5 is "respiratory").

[27] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[28] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

injection, the incremental increase in emission reduction capability falls. Thus, injecting more and more carbon will not necessarily result in greater emission reductions beyond a certain injection level. LEC asked EPA to evaluate the effect of diminishing returns on its conclusion that North Dakota lignite-powered facilities can achieve the standard designed for all other units of 1.2 lb/TBtu.

EPA does not appear to have taken the above concerns into account in claiming lignite- powered facilities can achieve the performance levels achieved at subbituminous plants. As a result, EPA has significantly underestimated the level of control needed to achieve the proposed standard of 1.2 lb/TBtu. Contrary to the analysis EPA relies upon to justify lowering the standard for lignite plants, control efficiencies of greater than 90 percent would be needed for North Dakota lignite-powered facilities.[29] LEC's comments asked EPA to reconsider its proposal in light of these concerns, and in light of EPA's legal obligation to ensure all standards are "achievable," which means they "must be capable of being met under most adverse conditions which can reasonably be expected to recur."[30]

The Administrative Record indicates a key reason why EPA's proposed standards are unachievable is the chemical composition of North Dakota lignite. For example, lignite has different heat and moisture content than subbituminous coals. As a result, a greater volume of fuel and air is needed at lignite plants to produce the same heat input compared to subbituminous plants. Due to higher fuel and air flows, a much greater volume of sorbent is needed to achieve similar emission reductions, and the additional sorbent dramatically increases cost, and therefore reduces the cost-effectiveness, of the controls.[31]

Another distinguishing difference EPA appeared to overlook in its proposal is the higher sulfur concentration in North Dakota lignite relative to subbituminous Powder River Basin coal, which in turn produces a higher level of sulfur trioxide ("SO3"). In the past, EPA has worked with a consultant that recognized this reality as follow:

> With flue gas SO3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.[32]

Cichanowicz et al. highlighted this passage from the S&L technology assessment and also noted that the presence of SO3 often affects capture rates in another way—by requiring units with measurable SO3 to be designed with higher gas temperature at the air heater exit to avoid corrosion that would otherwise occur if the SO3 is allowed to cool and condense on equipment

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[29] Cichanowicz Report, at 25, Table 6-1.

[30] *White Stallion Energy Center, LLC v. EPA*, 748 F.3d 1222, 1251 (2014) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n. 46 (D.C. Cir.1980)).

[31] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[32] Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology*, Project 12847-002, at 3 (Mar. 2013).

components. However, that higher exit gas temperature also impacts the effectiveness of sorbent injection systems—special-purpose tests on a fabric filter pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[33] The higher levels of SO_3 formed by the higher sulfur content found in lignite fuels will inhibit the ability of injected sorbents to reduce mercury emissions at lignite plants to a far greater extent than at subbituminous plants.

LEC agreed with these concerns in its comments and raised another important consideration — the fact that, unlike subbituminous plants, selective catalytic reduction (SCR) is technically infeasible on North Dakota lignite, due to its chemical composition. Although SCR systems are primarily installed for the control of nitrogen oxides (NO_X), SCR can enhance the oxidation of elemental mercury ("Hg^0") which facilitates removal in downstream control equipment, such as wet flue gas desulfurization (FGD) systems.[34] The higher level of mercury control achievable with an SCR is almost certainly why the one lignite plant (Oak Grove) evaluated by EPA as part of its review of the MATS RTR appears capable of achieving the mercury limit set for other coal ranks—it has an SCR that cannot be installed on North Dakota lignite facilities.[35]

LEC's comments also highlighted the experience of two LEC members that recently evaluated the difference in mercury control achieved by plants using subbituminous coal equipped with an SCR and plants using lignite coal without an SCR. Based on those evaluations, North Dakota lignite-powered facilities were found to have much greater difficulty reducing mercury emissions, despite using more than three times the amount of halogenated activated carbon than the subbituminous plant.

In the past, EPA has questioned whether SCR is technically feasible for North Dakota lignite-powered facilities, and recent research has confirmed that the significant challenges associated with using SCR on North Dakota lignite remain unresolved.[36] Although SCR has been demonstrated on the types of lignite found in other parts of the country, North Dakota lignite differs substantially in chemical makeup because it contains a much higher concentration of alkali metals (*e.g.*, sodium and potassium) that render the catalyst ineffective.[37]

In particular, the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 µm. As a vapor or as a very small particle, the sodium will pass through any upstream emissions control equipment (*e.g.*, electrostatic precipitators and scrubbers), and thus will reach the SCR regardless of whether the SCR is located before other emission control devices (high-dust configuration) or after those other controls (low-dust or tail-end configurations).[38]

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[33] Sjostrom 2016.

[34] 88 Fed. Reg. at 24875.

[35] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[36] *See* Draft SIP, App. D, at D.2.c-5 (citing Benson, Schulte, Patwardhan, Jones (2021) "The Formation and Fate of Aerosols in Combustion Systems for SCR NO_X Control Strategies" A&WMA's 114th Annual Conference, #983723).

[37] *Id.*

[38] *Id.*

Once the sodium particles reach the SCR, they plug the pores of the catalyst, which are the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive. Recent efforts to address these concerns through either cleaning or regeneration of the catalyst have not been successful, even at pilot scale. A study recently cited by DEQ in its regional haze plan provides additional details on these efforts and the unsolved technical challenges that remain regarding the impact of alkali metals in North Dakota lignite on the technical feasibility of SCR.[39]

According to LEC, its members report that efforts to identify a willing vendor for an SCR on a North Dakota lignite unit have been unsuccessful—all vendors have declined to offer SCR for use on North Dakota lignite once they have closely reviewed the unique characteristics that make SCR infeasible on that particular fuel.[40]

In short, the Administrative Record and other available evidence indicates that North Dakota lignite-powered facilities will likely not be able to meet the revised emission standards EPA is proposing for the MATS Rule.

The Administrative Record Indicates the Lower PM Standard May Also Not Be Technically Feasible

In addition to imposing a more stringent mercury standard on lignite by essentially eliminating the subcategory, EPA's proposal also lowers the standard on fPM for all existing units to the level previously deemed achievable only by new units. However, like its proposed Hg standard for lignite, EPA's proposal to revise the PM standard for all coal types remains unjustified by any demonstration of potential human health or environmental benefits.

The LEC's comments detail particular concerns associated with EPA's failure to provide a reasonable justification for so dramatically reducing the PM limit.[41] As LEC noted, the risks that the MATS Rule is designed to address have already been eliminated, down to several orders of magnitude below the level at which Congress directed EPA to stop regulating. The highest residual risk for the entire source category, which is based on an oil-fired unit, is just one tenth of EPA's acceptable level of risk, and the highest risk from any coal plant is more than an order of magnitude below the risk presented by oil-fired units.

Furthermore, the Administrative Record suggests that EPA's analysis of the achievability of the new 0.01 lb/mmBtu standard is based on an arbitrary data set, and that analysis also suffers from a lack of transparency. Specifically, commenters observed that EPA relies on a Sargent & Lundy memorandum that lacks sufficient detail or supporting documentation to verify the assumptions made, essentially hiding much of the agency's thought process behind the claim that the

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[39] *Id.*

[40] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[41] *Id.*

information on which it is based is not available in public forums.[42] In doing so, EPA seemingly commits what it has previously cited as error in plans developed by states and industry—failing to provide sufficient information to understand the reasoning underlying key conclusions.[43]

Moreover, the Administrative Record indicates the combined effect of both the proposal to require universal use of CEMS and the lower standard of 0.01 lb/mmBtu will present a compounded challenge if finalized as proposed. Commenters indicated that the difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate CEMS, and the difficulty in using CEMS will be exacerbated by the dramatically lower standard.[44] In particular, serious concerns remain with respect to whether a fPM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a CEMS to differentiate compliance from a false reading.[45] EPA attempts to allay these fears by claiming existing units can simply follow in the footsteps of new units, since new units have been subject to a CEMS requirement with a fPM emission limit of 0.090 lb/megawatt-hour since the inception of MATS.[46] **But that assurance provides no comfort—there are no new units.[47]**

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

Section C: Impact of MATS Regulations- Power Plant Economics and Grid Reliability

Power Plant Economic Impacts

The economic impacts for a lignite power plant from the Mercury and Air Toxics Standards (MATS) finalized rule can be substantial. The updated MATS rule, if implemented by the

[42] *PM Incremental Improvement Memo*, Doc. ID EPA-HQ-OAR-2018-0794-5836 (March 2023) ("Improvements to existing particulate control devices will be dependent on a range of factors including the design and current operation of the units, which is not documented in public forums. … Unfortunately, the details of how those units' ESP designs, upgrades, and operation are not publicly available …. In order to evaluate the applicability of one or more of these potential improvements, information would need to be known about the existing ESPs and their respective operation which is not documented in public forums.").

[43] *See, e.g., Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan*, 82 Fed. Reg. 32,294, 32,298 (July 13, 2017) ("Entergy's DSI and scrubber cost calculations were based on a propriety [sic] database, so we were unable to verify any of the company's costs. … Because of these issues, we developed our own control cost analyses ….").

[44] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[45] *Id.*

[46] 88 Fed. Reg. at 24874. The electrical output-based limit for new EGUs translates to approximately 0.009 lb/mmBtu, which is slightly below EPA's proposed limit of 0.010 lb/mmBtu.

[47] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

Environmental Protection Agency (EPA), aims to reduce mercury and other hazardous air pollutant emissions from coal-fired power plants. Coal-firing power plants, and lignite-firing power plants in particular, may face specific challenges and economic consequences in complying with these regulations, which could result in their forced retirement. Some potential economic impacts include:

1. **Escalating Operational Expenditures:** Under this rule, lignite power plants will face an excessive economic burden from a significant uptick in operational costs due to the integration of pollution control equipment. The installation of advanced technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates continuous monitoring and maintenance to ensure optimal performance. Design specifications vary from plant to plant which increases the complexities of the operating systems that require regular cleaning, replacement of consumables, and calibration, all of which incur additional expenses. Moreover, the implementation of pollution control, measures may necessitate alterations in combustion processes or the introduction of supplementary fuel, further driving up operational costs. As a result, lignite power plants are burdened with substantial ongoing expenditures, while also lacking a positive cost benefit analysis, which will undermine their economic viability and competitiveness in the energy market**.**

2. **Dilemma of Plant Retrofitting or Retirement:** Lignite power plants are confronted with the challenging prospect of either retrofitting existing facilities or contemplating retirement in response to the stringent requirements of the Mercury and Air Toxics Standards (MATS). Plant retrofitting involves substantial investment in upgrading equipment and implementing advanced pollution control technologies to achieve compliance with regulatory mandates. However, these retrofitting endeavors entail significant additional costs, potentially straining the financial resources of plant owners and operators. Moreover, the uncertainty surrounding the long-term economic viability of retrofitted plants further complicates decision-making processes**.**

3. **Impact on Electricity Prices:** The implementation of pollution control technologies to comply with MATS regulations can impose significant financial burdens on lignite power plants. These costs, encompassing the installation, maintenance, and operation of such technologies, would ultimately be transferred to consumers in the form of higher electricity prices. As power plants seek to recoup the expenses incurred in meeting regulatory requirements, consumers will experience an uptick in their electricity bills. This escalation in electricity prices will have far-reaching implications for households, businesses, and industries reliant on affordable energy. It will affect household budgets, impact the competitiveness of businesses, and influence consumer spending patterns. Additionally, higher electricity prices will introduce challenges for industries sensitive to energy costs, potentially leading to shifts in production, investment, and employment patterns within the broader economy. Therefore, the economic impact of elevated electricity prices resulting

from MATS compliance should be carefully considered within the context of the energy market, taking into account the implications for consumers, businesses, and overall economic growth.

4. **Employment Effects:** The escalation in costs and the possibility of plant retrofitting or retirement can reverberate through the lignite industry and associated sectors, potentially leading to job losses. As lignite power plants grapple with increased operational expenses and the financial strain of compliance with regulatory requirements, they may be compelled to streamline operations or even cease production altogether. Such decisions can have a ripple effect on employment within the community, impacting not only plant workers but also individuals employed in ancillary industries such as mining, transportation, and manufacturing. Job losses in these sectors can contribute to economic challenges, including reduced consumer spending, increased unemployment rates, and a decline in overall economic activity. Furthermore, the social and psychological impacts of job loss on affected individuals and communities cannot be understated, as they may face financial insecurity, stress, and uncertainty about their future prospects. Therefore, the potential job impacts stemming from increased costs and plant adjustments underscore the broader economic implications of regulatory compliance measures in the lignite industry.

5. **Regional Economic Consequences:** Lignite power plants are often linchpins of regional economies, exerting substantial influence on employment, tax revenue, and economic activity. Any shifts in the economic viability of these plants, whether due to increased costs, regulatory compliance burdens, or operational adjustments, will trigger broader consequences for local economies. The potential closure or downsizing of lignite power plants can result in the loss of direct and indirect employment opportunities, affecting not only plant workers but also individuals and businesses reliant on plant-related activities. Moreover, the decline in plant operations will lead to reduced tax revenue for local governments, impacting their ability to fund essential services and infrastructure projects. Additionally, the loss of economic activity associated with lignite power plants will ripple through the supply chain, affecting suppliers, vendors, and service providers in the region. This domino effect will exacerbate economic challenges, including decreased consumer spending, increased business closures, and a general downturn in economic vitality. Therefore, changes in the economic landscape of the lignite industry will have far-reaching consequences for regional economies, underscoring the interconnectedness between energy production, employment, and overall economic well-being at the local level.

6. **Impact on Investment Decisions:** The economic ramifications of the MATS rule can significantly shape investment decisions within the lignite industry. Plant owners and prospective investors must carefully evaluate the long-term economic feasibility and potential returns on investment in light of stringent regulatory compliance mandates. The substantial costs associated with MATS compliance, including technology upgrades and operational adjustments, may deter investment in lignite power plants or prompt

divestment from existing assets. Investors may reassess the risk-return profile of lignite-related ventures, considering factors such as regulatory uncertainty, market volatility, and shifting energy trends. Moreover, the potential for increased operational costs and regulatory burdens may incentivize investment in alternative energy sources or cleaner technologies, which align more closely with evolving environmental and sustainability objectives. Therefore, the economic implications of the MATS rule play a pivotal role in shaping investment decisions within the lignite industry, influencing capital allocation, project planning, and strategic resource allocation strategies.

7. **Legal and Regulatory Costs:** Meeting MATS requirements often entails significant legal and regulatory costs associated with monitoring, reporting, and ensuring continued compliance. Lignite power plants must allocate resources to navigate complex regulatory frameworks, engage legal counsel, and implement robust monitoring and reporting systems to adhere to emissions standards. These additional expenses contribute to the overall economic strain on lignite power plants, exacerbating the financial challenges associated with regulatory compliance. As a result, the burden of legal and regulatory costs further underscores the financial pressures faced by lignite power plant operators, shaping their strategic decision-making and resource allocation efforts.

Grid Reliability Impacts

Compliance with the Mercury and Air Toxics Standards (MATS) rule will likely have grid reliability impacts on regional power grids that rely on lignite- or other coal-firing power plants. The impacts on grid reliability for power grids that rely on lignite- or other coal-firing power plants can include:

1. **Operational Adaptations and Flexibility Constraints**: The implementation of pollution control technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates operational modifications within lignite power plants. These adjustments may include alterations to combustion processes, fuel handling procedures, and overall plant operations to accommodate the integration of new equipment and systems. However, such operational changes can compromise the inherent flexibility of lignite power plants to respond effectively to fluctuating load conditions and grid demands. The need for continuous operation of pollution control systems, coupled with potential limitations in responsiveness, may impede the plant's ability to ramp up or down quickly in response to changes in electricity demand or supply. Consequently, the reliability of lignite power plants to maintain grid stability and meet grid operator requirements may be compromised, raising concerns about their ability to ensure consistent and secure electricity supply. Thus, while MATS compliance aims to mitigate environmental impacts, the operational adaptations required may introduce challenges to the reliability and flexibility of lignite power plants in supporting a resilient and dynamic energy grid.

2. **Disruptions Due to Equipment Installation**: The installation and retrofitting of pollution control equipment often necessitate temporary shutdowns or reduced operating capacities within lignite power plants. These planned downtime periods are essential for integrating new equipment, conducting modifications, and ensuring compliance with regulatory requirements. However, the interruptions in plant operations during these installation phases will have adverse effects on the overall reliability and availability of the plant. The temporary cessation of power generation activities will disrupt electricity supply, potentially affecting grid stability and reliability. Moreover, extended downtime periods may lead to revenue losses for plant operators and suppliers, as well as inconvenience for consumers and end-users reliant on consistent electricity provision. Therefore, while essential for achieving compliance with MATS regulations, the equipment installation process poses challenges to the reliability and continuity of lignite power plant operations, emphasizing the importance of efficient planning and management to minimize disruptions.

3. **Efficiency Implications**: The introduction of pollution control technologies, especially those targeting mercury emissions reduction, will potentially undermine the overall efficiency of lignite power plants. While these technologies play a crucial role in meeting regulatory standards, they often require additional energy inputs and introduce operational complexities that can compromise plant efficiency. For instance, activated carbon injection (ACI) systems necessitate the injection of powdered carbon into the flue gas stream, which can increase resistance and pressure drops within the system, thus reducing overall efficiency. Similarly, flue gas desulfurization (FGD) systems require energy-intensive processes such as limestone slurry preparation and circulation, further impacting plant efficiency. The reduction in efficiency can translate to decreased electricity output per unit of fuel input, potentially affecting the plant's ability to generate electricity reliably and meet demand fluctuations. Consequently, while pollution control measures are essential for environmental protection, the associated efficiency implications underscore the need for careful optimization and balancing of environmental and operational considerations to ensure reliable power generation from lignite plants.

4. **Elevated Maintenance Demands**: The incorporation of MATS-compliant equipment, including ACI and FGD systems, often translates to heightened maintenance requirements within lignite power plants. The intricate nature of these pollution control technologies necessitates more frequent inspections, cleaning, and servicing to ensure optimal performance and regulatory compliance. However, the increased maintenance needs can result in extended periods of downtime, during which the plant may be unable to generate electricity, impacting its reliability and availability. Moreover, the allocation of resources and manpower to address maintenance tasks diverts attention and resources away from other operational activities, potentially affecting overall plant efficiency and productivity. Therefore, while essential for environmental compliance, the elevated maintenance

demands associated with MATS-compliant equipment pose challenges to the reliability and operational continuity of lignite power plants, highlighting the importance of proactive maintenance planning and execution to minimize disruptions.

5. **Inherent Fuel Supply Hurdles:** Lignite power plants grapple with inherent challenges associated with the utilization of lignite coal, particularly in meeting stringent emission standards. Lignite, characterized by its lower rank and elevated moisture content, poses unique obstacles in combustion processes. The variability in chemical composition across different seams of coal extracted from mines further complicates the task of ensuring consistent and efficient combustion. Each seam presents distinct combustion characteristics, necessitating meticulous adjustments in operational parameters to maintain compliance with emission regulations. Consequently, lignite power plants encounter difficulties in securing a reliable and uniform fuel supply, which undermines their ability to consistently meet emission targets and operational efficiency goals. The intricacies of managing diverse coal qualities exacerbate the complexities of pollution control measures, posing significant operational challenges for lignite power plants.

6. **Integration Challenges**: The introduction of new pollution control technologies into operational lignite power plants may encounter compatibility hurdles. Ensuring seamless integration with existing infrastructure is paramount for preserving reliability. Compatibility issues can emerge from differences in technology specifications, operational parameters, or control systems between the new equipment and the plant's established infrastructure. Unaddressed disparities may lead to operational inefficiencies, malfunctions, or system failures. Thus, meticulous planning and coordination are vital to mitigate compatibility risks and uphold the reliability of lignite power plants. Failure to address these challenges will compromise plant performance, emphasizing the need for thorough assessment and integration procedures when adopting new technologies.

7. **System Coordination and Grid Stability:** Adjustments in operating conditions and responses to fluctuating load demands can disrupt system coordination and compromise grid stability. Lignite power plants must coordinate closely with grid operators to maintain reliable electricity supply while adhering to MATS requirements. Changes in plant operations, such as implementing pollution control technologies or adjusting output levels, can affect the overall balance of supply and demand within the grid. Without effective coordination, these changes may lead to imbalances, voltage fluctuations, or frequency deviations, posing risks to grid stability. Therefore, robust communication and collaboration between lignite power plants and grid operators are essential to ensure seamless integration of plant operations with broader grid dynamics. By coordinating effectively, lignite power plants can contribute to grid stability while meeting regulatory obligations, ensuring the reliable delivery of electricity to consumers.

8. **Continuous Compliance Management**: Adhering to emission limits mandated by MATS necessitates ongoing monitoring and fine-tuning of pollution control equipment. The chemical properties of lignite can vary even within coal seams from the same mine, posing challenges in preparation and adjustment for plant operations. This variability complicates efforts to maintain consistent compliance, requiring dynamic adjustments in day-to-day plant operations. Consequently, ensuring reliable compliance becomes a dynamic process, demanding meticulous attention to detail and proactive management of pollution control systems. Consistent monitoring and adjustment are essential to mitigate emissions effectively while sustaining the operational reliability of lignite power plants amidst the inherent variability of lignite coal properties.

9. **Supply Chain Vulnerabilities:** The consolidation in the power plant equipment sector over the past decade has reduced the number of suppliers available. Relying on specific suppliers for pollution control equipment and technologies introduces supply chain risks. Disruptions in the supply chain, such as shortages, delays, or quality issues, will impede the timely installation and operation of essential equipment, jeopardizing reliability. Lignite power plants must carefully assess and manage these supply chain vulnerabilities to ensure uninterrupted access to critical components and technologies necessary for regulatory compliance and operational integrity. Proactive measures, such as diversifying suppliers or implementing contingency plans, are crucial for mitigating supply chain risks and maintaining the reliability of lignite power plants.

10. **Long-Term Viability and Aging Infrastructure:** Compliance with MATS regulations will raise concerns about the long-term viability of older lignite power plants. Aging infrastructure may struggle to adapt to the requirements of new pollution control technologies, posing challenges that will impact reliability. The integration of these technologies into outdated systems may require extensive retrofitting or upgrades, which can strain resources and prolong downtime. Moreover, the operational lifespan of aging infrastructure may be limited, leading to questions about the economic feasibility of investing in costly compliance measures. Plant owners must carefully assess the cost-benefit ratio of compliance efforts and consider the potential impact on reliability when evaluating the long-term viability of older lignite power plants. Failure to address these challenges will compromise the reliability and competitiveness of these facilities in the evolving energy landscape.

Section D: Modeling Results

Summary

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case, instead it conducted a Resource Adequacy and reserve margin analysis, which EPA has claimed is necessary but not sufficient to grid reliability.[48]

EPA's lack of reliability modeling prompted several entities to voice concerns in the original docket for the Proposed MATS rule would negatively impact grid reliability, including the National Rural Electric Coop Association, the American Coal Council, The Lignite Energy Council, PGen, the American Public Power Association, and the National Mining Association.[49,50,51,52,53,54]

To provide this necessary perspective, Center of the American Experiment modeled the reliability and cost impacts of the proposed Mercury and Air Toxics Standards (MATS) in the subregions consisting of the Midcontinent Independent Systems Operator (MISO) as it relates to the elimination of the subcategory for lignite-fired power plants.[55,]

Our analysis determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system if these resources are replaced with wind, solar, battery storage, and natural gas plants consistent with the EPA's estimates for capacity values for intermittent and thermal resources.

Building these replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost \$12.93 billion, \$14.88 billion, and \$16.76 billion, respectively, from 2024 through 2035, resulting in incremental costs of \$1.9 billion in the Partial

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[48] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[49] NRECA Comments, EPA-HQ-OAR-2018-0794-5956, at 5-6.
[50] American Coal Council Comments, EPA-HQ-OAR-2018-0794-6808, at 3.
[51] LEC Comments, EPA-HQ-OAR-2018-0794-5957, at 17.
[52] PGen Comments, EPA-HQ-OAR-2018-0794-5994, at 5.
[53] APPA Comments, EPA-HQ-OAR-2018-0794-5958, at 33.
[54] NMA Comments, EPA-HQ-OAR-2018-0794-5986, at 29.
[55] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.

scenario and $3.8 billion in the Full scenario through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts, which can result in food spoilage, property damage, lost labor productivity, and loss of life. American Experiment calculated the economic damages associated with the increase in unserved electricity demand using a metric called the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Our analysis found that the MATS rule would cause an additional 73,699 additional megawatt hours (MWh) of unserved load in the in the Full MATS Retirement scenario in 2035 using 2019 hourly electricity demand and wind and solar capacity factors. Using a conservative value for the VoLL of $14,250 per MWh, we conclude the MATS rule would produce economic damages of $1.05 billion under these conditions.

Therefore, the incremental costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO under the Full scenario exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.

Modeling the Reliability and Cost of the MISO Generating Fleet Under Three Scenarios

Our analysis examined the impact of the proposed MATS rules on the reliability of the MISO system through 2035 by comparing two lignite retirement scenarios to a "Status Quo" scenario that represents "business as usual" that assumes no changes to the generating fleet occur due to the MATS rule, or any other of EPA's pending regulations.[56]

Status Quo scenario: Installed generator capacity assumptions for MISO in the Status Quo scenario are based on announced retirements from U.S. Energy Information Administration (EIA) database and utility Integrated Resource Plans (IRPs) through 2035 compiled by Energy Ventures Analysis on behalf America's Power, a trade association whose sole mission is to advocate at the federal and state levels on behalf of the U.S. coal fleet.[57] This database is also used by the NERC LTRA suggesting it is among the most credible databases available for this analysis.[58] It should be noted that this database leaves considerably more coal and natural gas on its system than the MISO grid EPA assumes will be in service in the coming years in its Proposed Rule Supply Resource

[56] See Appendix 2: Capacity Retirements and Additions in Each Scenario.
[57] America's Power, "Proprietary data base maintained by Energy Ventures Analysis, an energy consultancy with expertise in electric power, natural gas, oil, coal, renewable energy, and environmental policies" Personal Communication, November 3, 2023.
[58] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Utilization file, meaning our reliability assessment will be more conservative than if we used EPA's capacity projections.

Retired thermal resources in the Status Quo scenario are replaced by solar, wind, battery storage, and natural gas in accordance with the current MISO interconnection queue to maintain resource adequacy based on capacity values given to these generators in EPA's Proposed Rule Supply Resource Utilization file.[59] These capacity values are described in greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.

Partial MATS Retirement scenario: The Partial MATS retirement scenario assumes 1,150 megawatts (MW) of lignite fired capacity in North Dakota is retired in addition to incorporating all of the announced retirements in the Status Quo. This value was chosen because it represents the retirement of one lignite facility in North Dakota that serves the MISO market. These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[60]

Full MATS scenario: The Full MATS retirement scenario assumes the MATS regulations will cause all 2,264 MW of lignite-fired generators in the MISO system to retire, in addition to incorporating the retirements in the Status Quo scenario will occur.[61] These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[62]

Reliability in each scenario

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case. Instead, it conducted a Resource Adequacy analysis of its proposed rule, compared to the Post IRA base case.

Resource Adequacy and reserve margin analyses can be useful tools for determining resource adequacy and reliability, but the shift away from dispatchable thermal resources (fossil fuel) toward intermittent resources (wind and solar) increases the complexity and uncertainty in these analyses and makes them increasingly dependent on the quality of the assumptions used to construct capacity accreditations.[63]

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[59] U.S. Environmental Protect Agency, "Proposed Regulatory Option," Zip File, https://www.epa.gov/system/files/other-files/2023-04/Proposed%20Regulatory%20Option.zip
[60] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[61] These figures represent the rated summer capacity as indicated by the U.S. Energy Information Administration.
[62] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[63] See Appendix 4: Resource Adequacy in Each Scenario.

This is likely a key reason why EPA has distinguished between resource *adequacy* and resource *reliability* in its Resource Adequacy Technical Support Document for its proposed carbon dioxide regulations on new and existing power plants.[64,65] EPA stated:

> "As used here, the term **resource adequacy** is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while **reliability** includes the ability to deliver the resources to the loads, such that the overall power grid remains stable." **[emphasis added].**" EPA goes on to say that "resource adequacy … is necessary (but not sufficient) for grid reliability.[66]

As the grid becomes more reliant upon non-dispatchable generators with lower reliability values, it is crucial to "stress test" the reliability outcomes of systems that use the EPA's capacity value assumptions in their Resource Adequacy analyses by comparing historic hourly electricity demand and wind and solar capacity factors against installed capacity assumptions in the Status Quo, Partial, and Full scenarios.

We conducted such an analysis by comparing EPA's modeled MISO generation portfolio to the historic hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, and 2022. These data were obtained from the U.S. Energy Information Administration (EIA) Hourly Grid Monitor to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).[67]

For our analysis, hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions. These assumptions are generous to the EPA because they increase the annual output of wind and solar generators to levels that are not generally observed in MISO.

Extent of the Capacity Shortfalls

While our modeling determined that the retirement of lignite facilities had a minimal impact on the number of hours of capacity shortfalls observed in the Partial and Full scenarios, retiring the lignite facilities makes the extent of capacity shortfalls worse.

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[64] EPA did not produce a Resource Adequacy Technical Support Document for the MATS rules.

[65] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.

[66] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.

[67] U.S. Energy Information Administration, "Hourly Grid Monitor," https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

For example, Figure D-1 shows largest capacity shortfalls in the Status Quo scenario, which occur in 2035 using the 2021 Historical Comparison Year for hourly electricity demand and wind and solar capacity factors.

Each resource's hourly performance is charted in the graph below. Thermal units are assumed to be 100 percent available, which is consistent with EPA's capacity accreditation for these resources, and wind and solar are dispatched as available based on 2021 fluctuations in generation. Blue sections reflect the use of "Load Modifying Resources," which are reductions in electricity consumption by participants in the MISO market.

Purple areas show time periods where the batteries are discharged. These batteries are recharged on January 8th and 9th using the available natural gas and oil-fired generators. Red areas represent periods where all of the resources on the grid are unable to serve load due to low wind and solar output and drained battery storage systems. At its peak, the largest capacity shortfall is 15,731 MW.

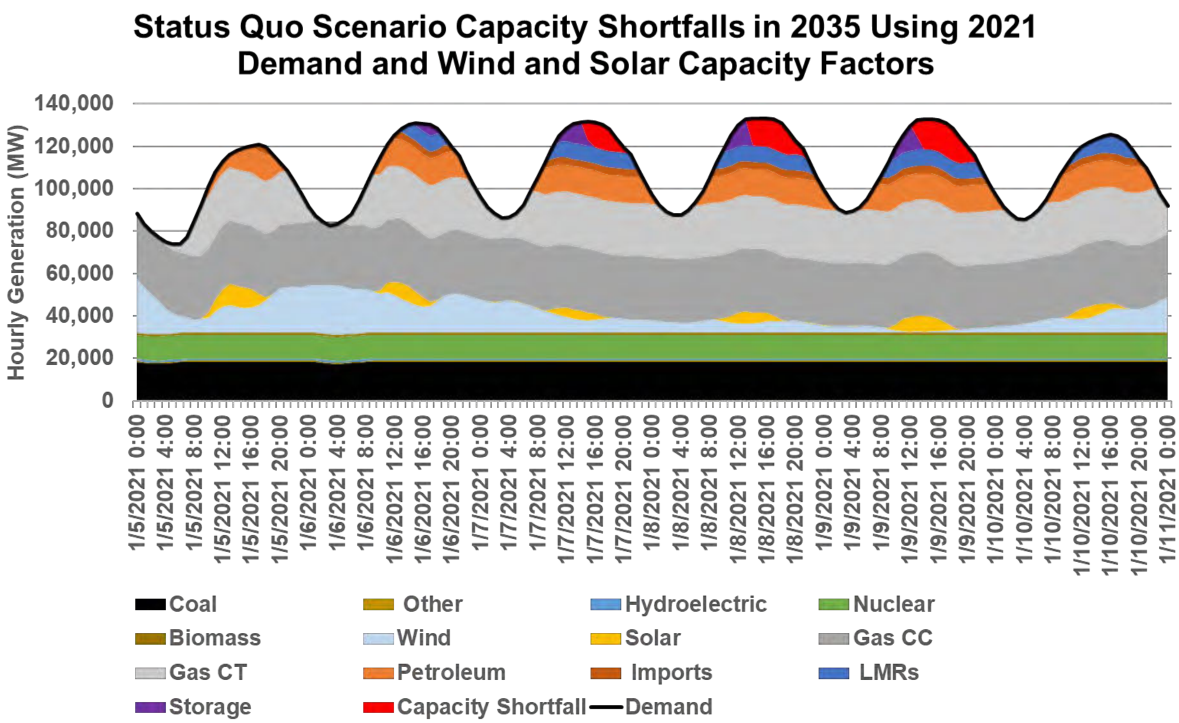

Figure D-1. This figure shows the generation of resources on the MISO grid in the Status Quo during a theoretical week in 2035. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage does not last long enough to avoid blackouts during a wind drought.

These capacity shortfalls become more pronounced in the Partial and Full scenarios as less dispatchable capacity exists on the grid to serve load. Figure D-2 shows the three capacity shortfall events in Figure D-1. It depicts the blackouts observed in the Status Quo scenario in green, and the additional MW of unserved load in the Partial and Full scenarios in yellow and red, respectively.

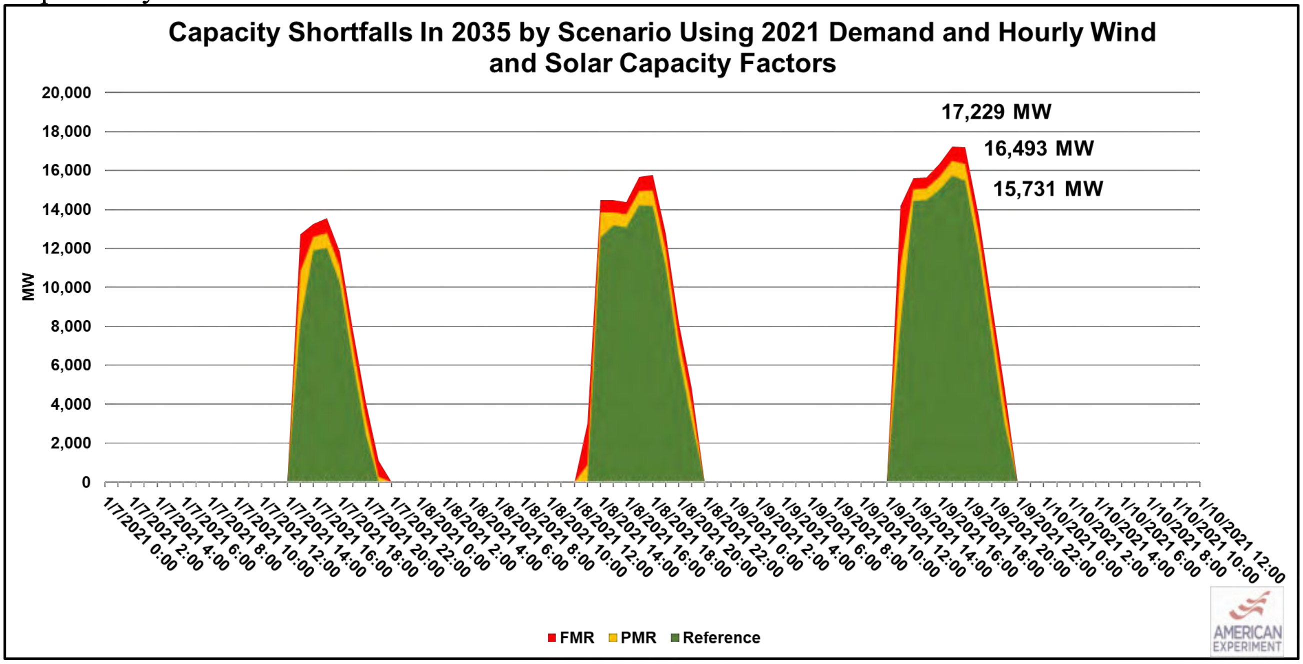

Figure D-2. Capacity shortfalls increase during a hypothetical January 9th, 2035 from 15,731 MW at their peak in the Status Quo to 16,493 MW in the Partial scenario and 17,229 MW in the Full scenario.

Table D-1 shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfall due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

The largest incremental increase in capacity shortfalls would occur in the 2020 HCY in the Full scenario as the blackouts would increase from 552 MW in the Status Quo scenario to 3,295 in the Full scenario, a difference of 2,743 MW.

Maximum MW Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	15,130	15,842	712	16,530	1,400
2020	552	2,587	2,034	3,295	2,743
2021	15,731	16,493	762	17,229	1,498
2022	10,615	11,409	794	12,177	1,562

Table D-1. This table shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfalls due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

It is important to note that this difference is larger than the amount of lignite-fired capacity that is retired in the Full scenario (2,264 MW) because the retirement of these facilities reduces the amount of capacity available to charge battery storage resources.

Unserved MWh in Each Scenario

The amount of unserved load in each scenario can also be measured in megawatt hours (MWh). This metric is a product of the number of hours with insufficient energy resources multiplied by the hourly energy shortfall, measured in MW. This metric may be a more tangible way to understand the impact that the unserved load will have on families, businesses, and the broader economy. Each MWh reflects an increment of time where electric consumers in the MISO grid will not have access to power.

Table D-2 shows the number of MWhs of unserved load in each scenario for the four HCYs studied. In some HCYs, the incremental number of unserved MWhs is fairly small, but in other years they are substantial. In the 2020 HCY, the Partial scenario had 2,042 more MWhs of unserved load than the Status Quo scenario, and the Full scenario had 4,265 MWh of additional unserved load, compared to the Status Quo Scenario.

Total MWh Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	168,723	204,050	35,327	242,393	73,669
2020	582	2,624	2,042	4,847	4,265
2021	244,743	273,927	29,184	304,021	59,278
2022	53,458	62,223	8,765	71,304	17,846

Table D-2. The incremental MWh of unserved load ranges from 2,042 to 35,327 in the Partial scenario, and from 4,265 to 73,669 in the Full scenario.

In the 2019 HCY, the Partial scenario experienced an additional 35,327 MWh of unserved load and the Full scenario experienced 73,669 MWh of unserved load. These additional MWh of unserved load will impose hardships on families, businesses, and the broader economy.

The Social Cost of Blackouts Using the Value of Lost Load (VoLL)

Blackouts are costly. They frequently result in food spoilage, lost economic activity, and they can also be deadly. Regional grid planners attempt to quantify the cost of blackouts with a metric called the Value of Lost Load (VoLL). The VoLL is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

MISO currently assigns a Value of Lost Load (VOLL) of $3,500 per megawatt hour of unserved load. However, Potomac Economics, the Independent Market Monitor for MISO, recommended a value of $25,000 per MWh for the region.[68] For this study, we used a midpoint value of $14,250 per MWh of unserved load to calculate the social cost of the blackouts under each modeled scenario.

Table D-3 shows the economic damage of blackouts in each scenario in model year 2035 and shows the incremental increase in the VOLL in the Partial and Full scenarios. Incremental VOLL costs are highest using the 2019 HCY where MISO experiences an additional $503.4 million in economic damages due to blackouts in the Partial scenario, and an additional $1.05 billion in the Full scenario.

Value of Lost Load for Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	$2,404,309,657	$2,907,716,665	$503,407,008	$3,454,098,692	$1,049,789,035
2020	$8,296,505	$37,389,117	$29,092,612	$69,074,216	$60,777,712
2021	$3,487,594,170	$3,903,464,847	$415,870,677	$4,332,301,464	$844,707,294
2022	$761,782,023	$886,680,023	$124,898,001	$1,016,083,680	$254,301,657

Table D-3. MISO would experience millions of dollars in additional economic damage if the lignite fired power plants in its footprint are shut down in response to the MATS regulations.

It is important to note that these VOLL figures are not the total estimated cost impacts of blackouts for the MATS regulations. Rather, they are a snapshot of a range of possible outcomes for the year 2035 based on variations in electricity demand and wind and solar productivity.

The VOLL demonstrates harm of the economy in a multitude of ways. For the industrial/commercial sector, direct costs from losing power (and therefore benefits from avoiding power outages) can be (1) opportunity cost of idle resources, (2) production shortfalls / delays, (3) damage to equipment and capital, and (4) any health or safety impacts to employees. There are also indirect or macroeconomic costs to downstream businesses/consumers who might depend on the products from a company who experiences a power outage.[69]

For the residential sector, the direct costs are different. They can include (1) restrictions on activities (e.g. lost leisure time, lost work time, and associated stress), (2) financial costs through property damage (e.g. damage to real estate via bursting pipes, food spoilage), and (3) health and safety issues (e.g. reliance on breathing machines, air filters).[70]

[68] David B. Patton, "Summary of the 2022 MISO State of the Market Report," Potomac Economics, July 13, 2023, https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf.
[69] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.
[70] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

Hours of Capacity Shortfalls

Comparing hourly historic electricity demand and wind and solar output to MISO grid in the Status Quo scenario, our modeling found that MISO would have capacity shortfalls in the 2019, 2021, and 2022 HCYs which can be seen in Table D-4 below.

There would be additional capacity shortfalls in all of the HCYs modeled in the Partial and Full scenarios, where the Partial scenario would experience four additional hours of blackouts in 2019 HCY, one additional hour of blackouts in the 2020 HCY, four additional hours of blackouts in 2021 HCY, and one additional hour of blackouts in the 2022 HCY. In the Full scenario, there would be five additional hours of blackouts in the 2019 HCY, one additional hour of blackouts in the 2020 HCY, eight additional hours in the 2021 HCY, and two additional hours in the 2022 HCY, compared to the Status Quo Scenario.

Hours of Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	28	32	4	33	5
2020	2	3	1	3	1
2021	24	28	4	32	8
2022	13	14	1	15	2

Table D-4. Capacity shortfalls occur in three of the four HCYs in the Status Quo scenario and all four HCYs for the Partial and Full scenarios.

Cost of replacement generation

Our VOLL analysis demonstrates that the MATS rules will cause significant economic harm in MISO by reducing the amount of dispatchable capacity on the grid due to lignite plant closures stemming from the removal of the lignite subcategory.

However, load serving entities (LSEs) will also begin to incur costs as they build replacement generation to maintain resource adequacy if lignite resources are forced to retire in response to the proposed MATS rules. These costs will be passed on to electricity consumers and must be calculated to produce accurate estimates of the true cost of the MATS regulations.

We modeled the cost of the replacement generation under the Status Quoe, Partial and Full scenarios. The cost of the Partial and Full scenarios, when compared to the Status Quo scenario, is used to determine the additional economic burden that the MATS regulations will impose onto MISO electricity customers.

Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035 (see Figure D-3).

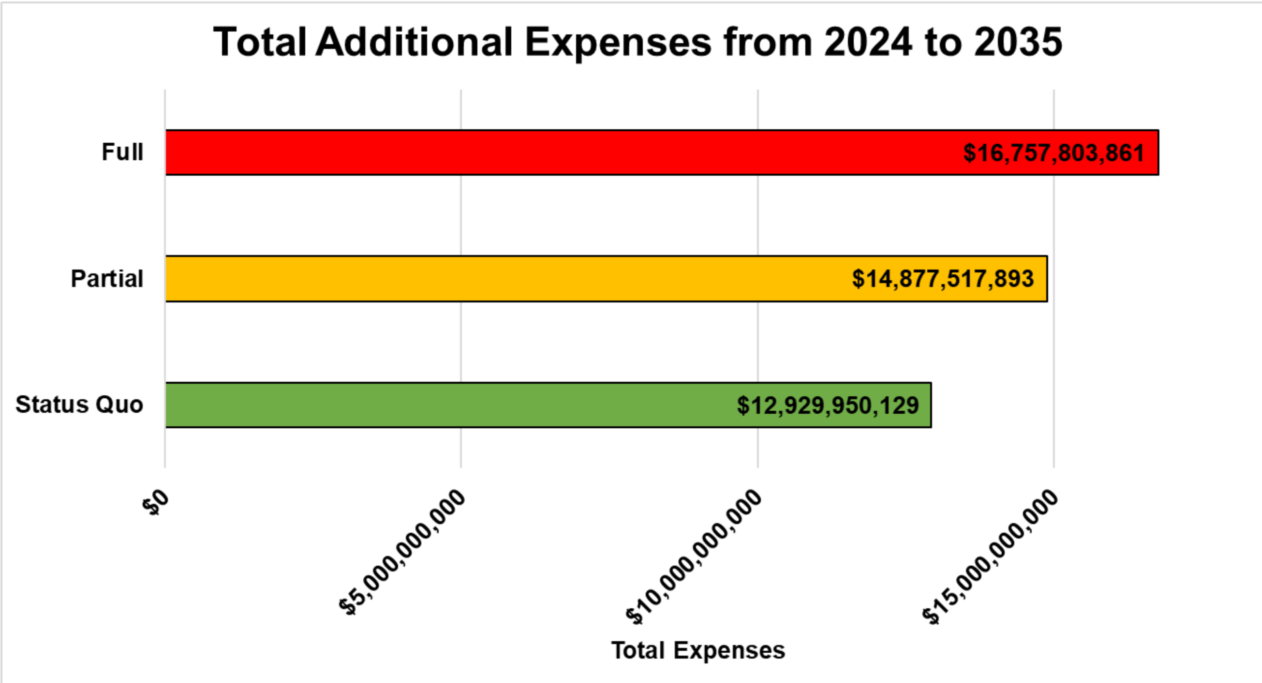

Figure D-3. The Partial scenario will cost $1.95 billion more than the Status Quo scenario from 2024 through 2035 and the Full scenario will cost $3.8 billion more than the Status Quo scenario in this timeframe.

Figure D-4 shows the incremental cost of the Partial and Full scenarios from 2024 through 2030, the period reflecting the up-front costs of complying with the regulations. From 2024 through 2028, LSEs would incur $337 million by building replacement generation in the Partial scenario, compared to the Status Quo scenario, and $654 million in the Full scenario, relative to the Status Quo. It should be noted that these costs are only the cost of building replacement generation and do not factor in the cost of decommissioning or remediating existing power plants or mine sites.

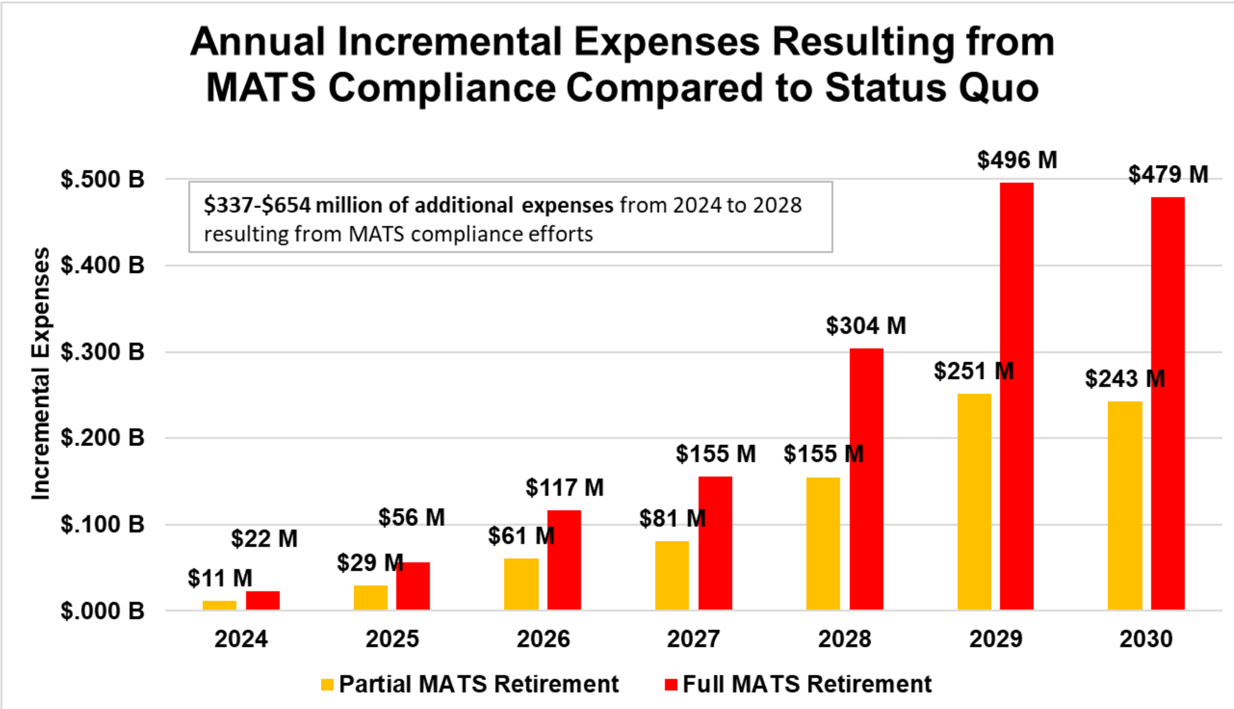

Figure D-4. This figure shows the annual cost of building the replacement capacity needed to maintain resource adequacy after the retirement of the lignite plants based on EPA's capacity accreditation values for wind, solar, storage, and thermal resources.

We describe the total costs of replacement generation capacity for each scenario in greater detail below. The assumptions used to calculate the cost of replacement generation can be found in Appendix 1: Modeling Assumptions.

Status Quo scenario:

The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. These retirements are already projected to occur without imposition of the new MATS Rule or other federal regulations. This retired capacity is replaced with 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.[71]

The total cost of replacement generation for the Status Quo scenario is $12.9 billion. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Status Quo scenario saves $32 billion in fuel costs, $11.5 billion in variable operations and maintenance costs, and $5 billion in taxes. However, these savings are

[71] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

far outweighed by $5.1 billion in additional fixed costs, $16 billion in capital costs, $2.1 billion in transmission costs, and $38.2 billion in utility profits (see Figure D-5).

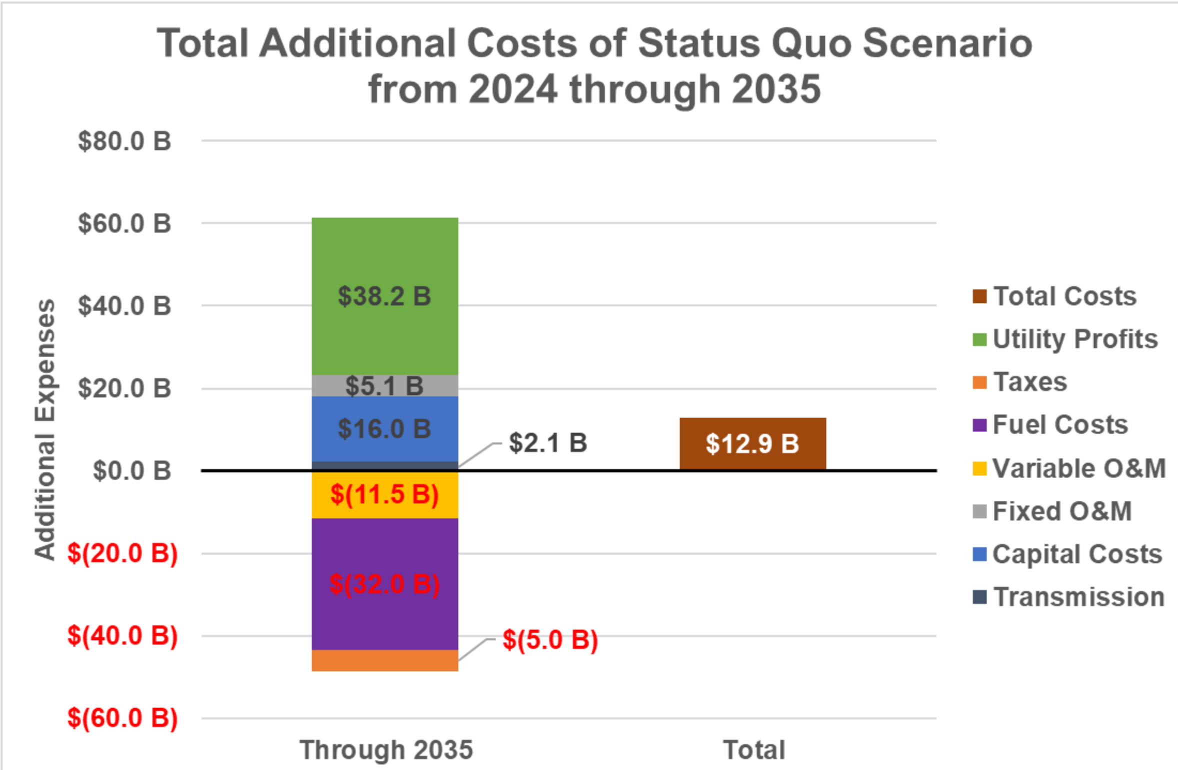

Figure D-5. The Status Quo scenario saves consumers money from lower fuel costs, fewer variable operations and maintenance costs, and lower taxes (due to federal subsidies) but these savings are outweighed by the additional costs. As a result, building the grid in the Status Quo scenario would increase costs by $12.93 billion compared to today's costs.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.89 cents per kWh in the Status Quo scenario, an increase of nearly 3.5 percent relative to current costs of 9.56 cents per kWh.[72]

Partial MATS Retirement scenario:

The Partial scenario results in the closure of 1,151 MW of lignite capacity and necessitates an incremental increase in replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage, compared to the Status Quo scenario.[73]

The total cost of replacement generation for the Partial scenario is $14.9 billion, and the total incremental cost is $1.9 billion compared to the Status Quo scenario. The majority of these

[72] Annual Electric Power Industry Report, Form EIA-861 detailed data files, https://www.eia.gov/electricity/data/eia861/.
[73] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Partial scenario saves $32.7 billion in fuel costs, $11.6 billion in variable operations and maintenance costs, and $5.1 billion in taxes. However, these savings are far outweighed by $5.3 billion in additional fixed costs, $17.1 billion in capital costs, $2.2 billion in transmission costs, and $39.7 billion in utility profits (see Figure D-6).

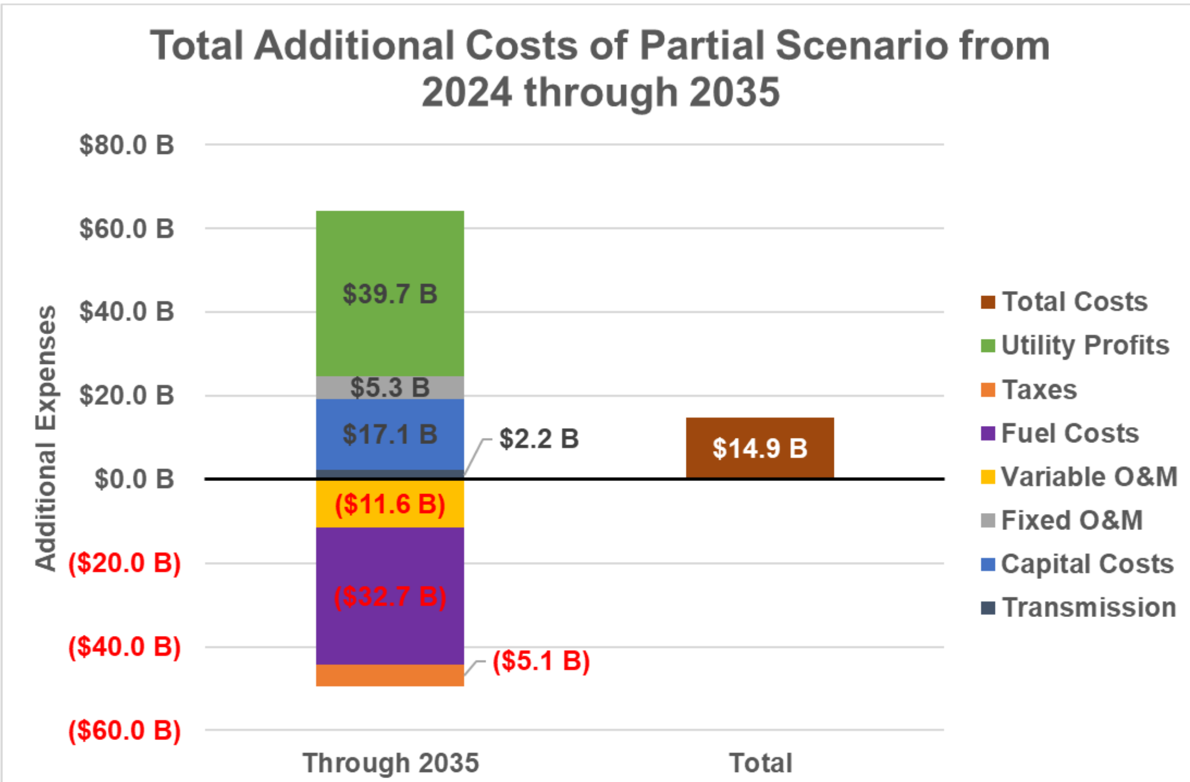

Figure D-6. The Partial scenario results in an $14.88 billion in additional costs compared to the current grid due to additional capital costs, fixed operations and maintenance costs, additional transmission costs, and additional utility profits.

Compared to the Status Quo scenario, the incremental savings are $664 million in fuel costs, $119.7 million in variable operations and maintenance costs, and $102.2 million in taxes, which are outweighed by $178.7 million in additional fixed costs, $1.1 billion in capital costs, $116.5 million in transmission costs, and $1.4 billion in utility profits (see Figure D-7).

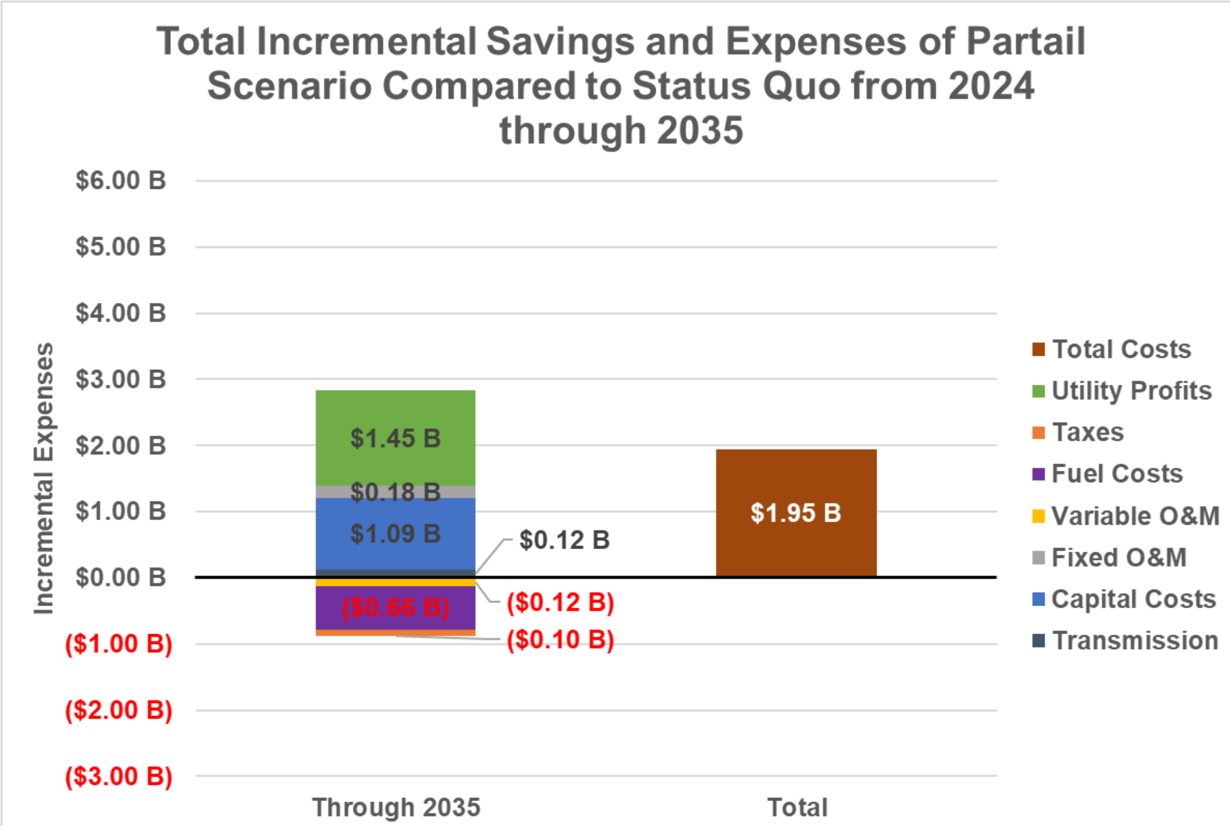

Figure D-7. The Partial scenario will cost MISO ratepayers an additional $1.9 billion from 2024 through 2035.

These incremental costs mean Load Serving Entities will incur an additional $1.9 billion because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $337 million of additional expenses compared to the Status Quo scenario (see Figure D-8).

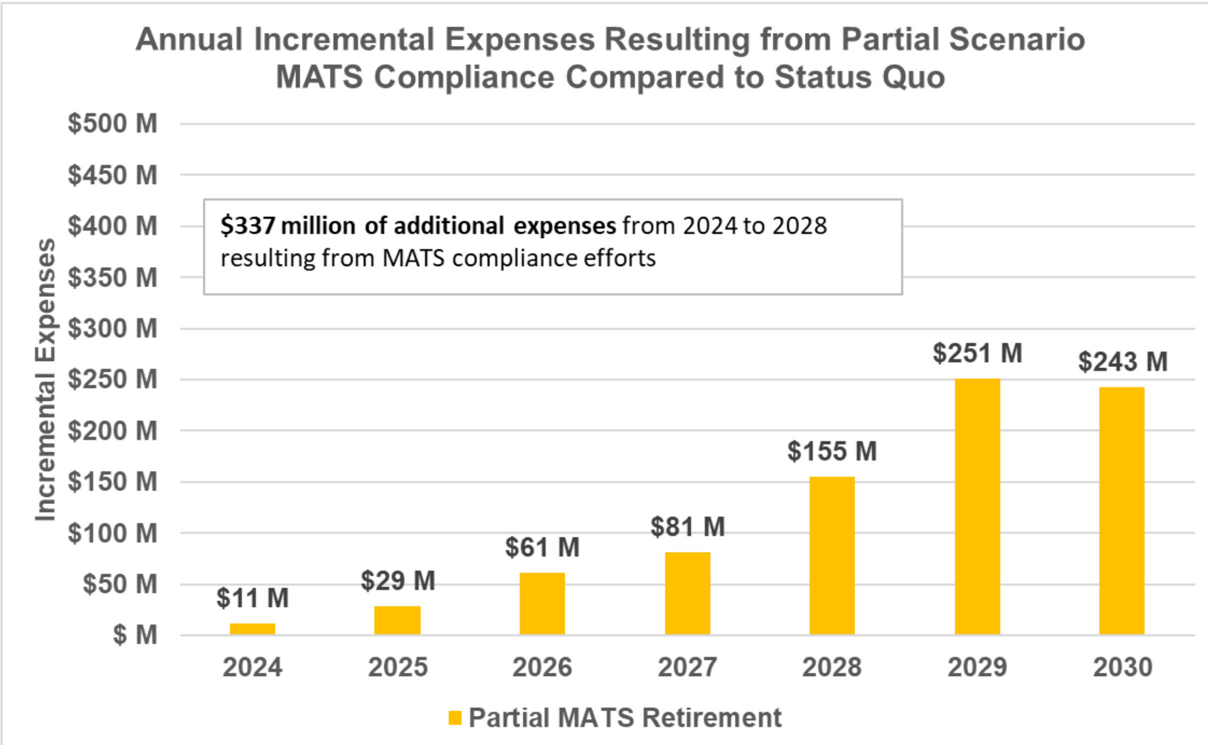

Figure D-8. This figure shows the annual incremental cost incurred by LSEs as a result of the lignite closures in the Partial scenario.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.95 cents per kWh in the Partial scenario, an increase of nearly 3.9 percent relative to current costs of 9.58.

Full MATS scenario:

Under the Full scenario, 2,264 MW of lignite capacity would be forced to retire resulting results in an incremental increase in replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage compared to the Status Quo scenario.

The total cost of replacement generation for the Full scenario is $16.8 billion, and the total incremental cost is $3.8 billion compared to Status Quo scenario. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Full scenario saves $33.3 billion in fuel costs, $11.7 billion in variable operations and maintenance costs, and $5.2 billion in taxes. However, these savings are far outweighed by $5.4 billion in additional fixed costs, $18.1 billion in capital costs, $2.4 billion in transmission costs, and $41.1 billion in utility profits (see Figure D-9).

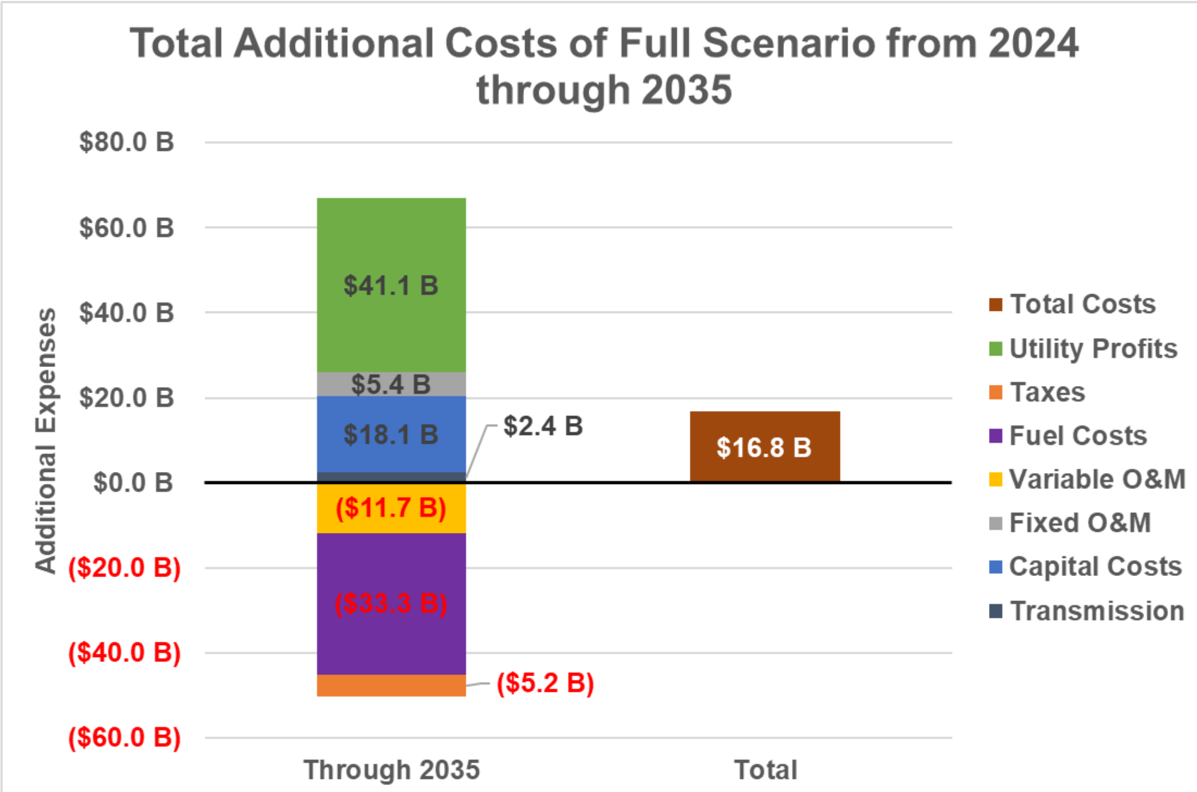

Figure D-9. The Full scenario results in an increase of $16.76 billion in costs compared to the current grid.

Compared to the Status Quo scenario, the incremental savings are $1.3 million in fuel costs, $235.1 million in variable operations and maintenance costs, and $202 million in taxes, which are outweighed by $350.8 million in additional fixed costs, $2.1 billion in capital costs, $229.1 million in transmission costs, and $2.8 billion in utility profits (see Figure D-10).

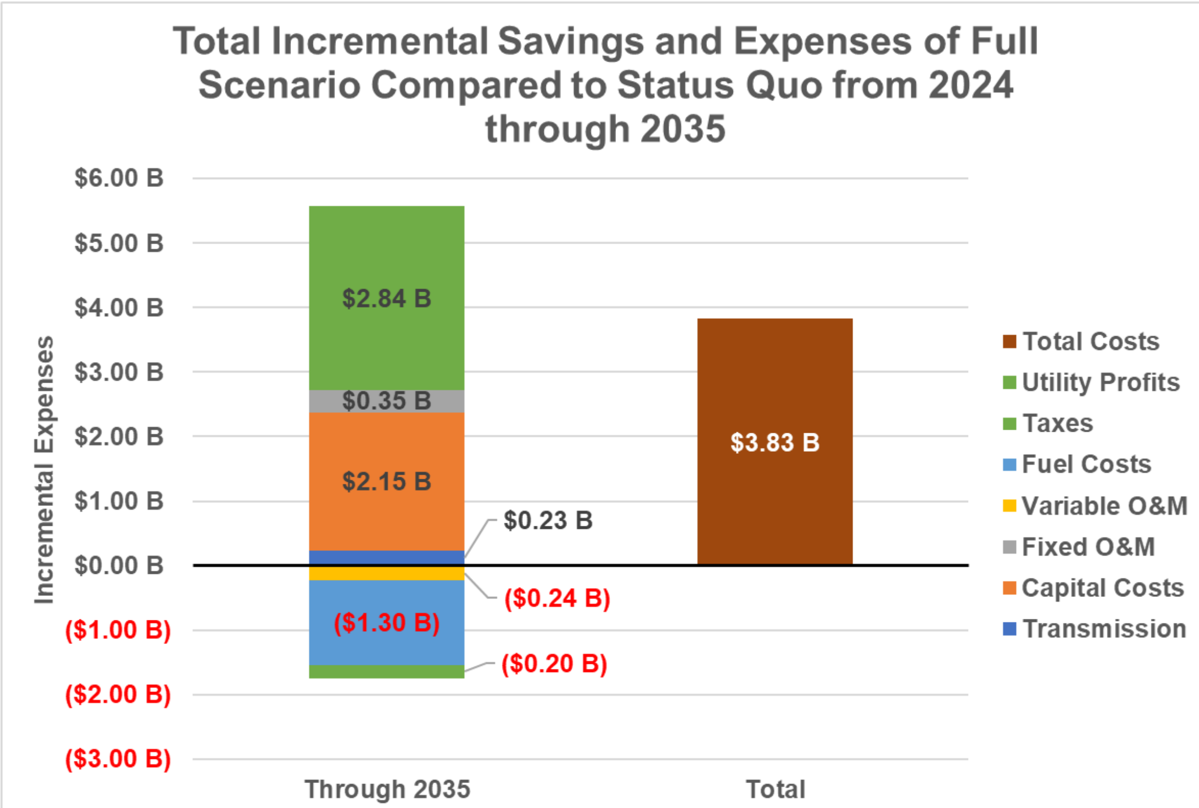

Figure D-10. This figure itemizes the expenses incurred in the Full scenario, which will cost an additional $3.8 billion compared to the Status Quo scenario.

These incremental costs mean Load Serving Entities will incur an additional $3.8 billion in the Full scenario because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $654 million of additional expenses compared to the Status Quo scenario (see Figure D-11).

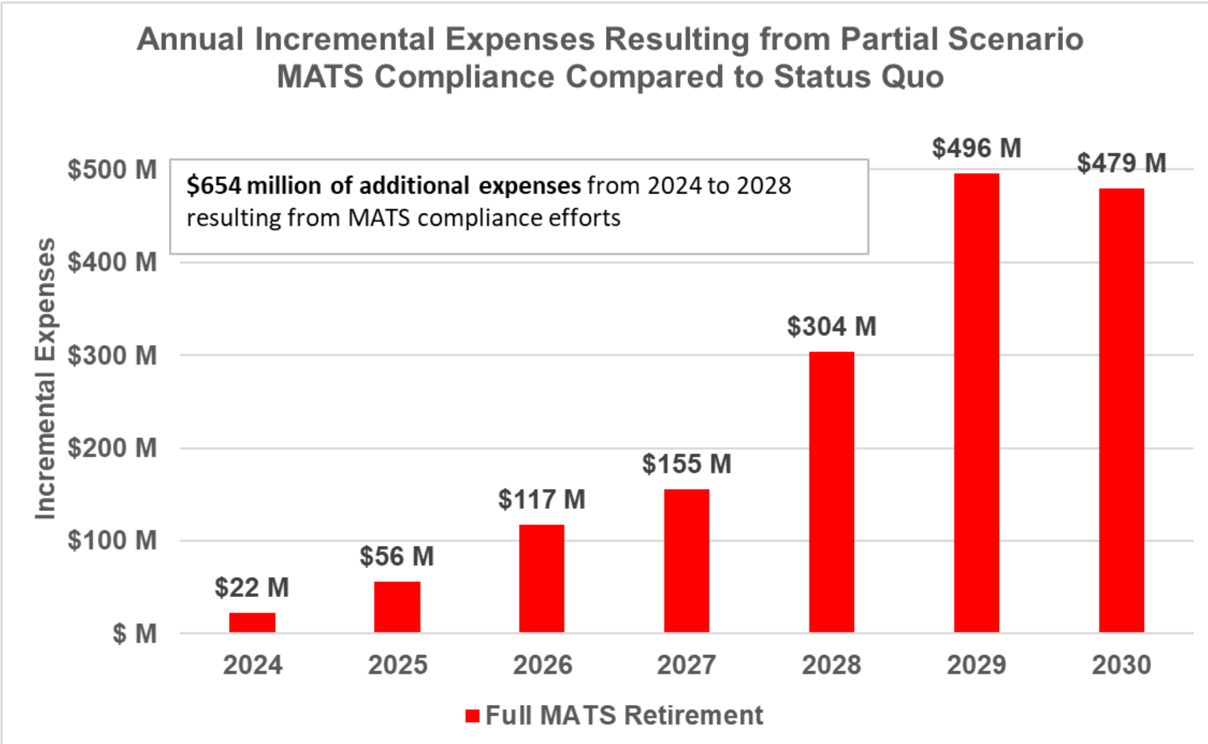

Figure D-11. LSEs would incur an additional $654 million in additional expenses, compared to the Status Quo scenario, as a result of the proposed MATS rules.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.97 cents per kWh in the Full scenario, an increase of nearly 4.1 percent relative to current costs of 9.58.

Conclusion:

By effectively eliminating the subcategory for lignite power plants and ignoring the breadth of evidence demonstrating that these regulations are not reasonably attainable, the MATS rules will increase the severity of capacity shortfalls in the MISO region, resulting in economic damages from the ensuing blackouts ranging from $29 million to $1.05 billion, depending on the HCY used, and imposing $1.9 billion to $3.8 billion in the cost of replacement generation capacity in the Partial and Full scenarios, respectively.

Therefore, the costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.[74]

[74] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.

Appendix 1: Modeling Assumptions

Electricity Consumption Assumptions

Annual electricity consumption in each model year is increased in accordance with EPA's assumptions in the IPM in each of the MISO subregions.

Peak Demand and Reserve Margin Assumptions

The modeled peak demand and reserve margin in each of the model years are increased in accordance with the IPM in each of the MISO subregions.

Time Horizon Studied

This analysis studies the impact of the proposed MATS rules from 2024 through 2035 to accurately account for the costs LSEs would incur by building replacement generation in response to the potential shutdown of lignite capacity.

This timeline downwardly biases the cost of compliance with the regulations because power plants are long term investments, often paid off over a 30-year time period. This means the changes to the resource portfolio in MISO resulting from these rules will affect electricity rates for decades beyond 2035.

Hourly Load, Capacity Factors, and Peak Demand Assumptions

Hourly load shapes and wind and solar generation were determined using data for the entire MISO region obtained from EIA's Hourly Grid Monitor. Load shapes were obtained for 2019, 2020, 2021, and 2022. [75] These inputs were entered into the model to assess hourly load shapes and assess possible capacity shortfalls in 2035 using each of the historical years.

Capacity factors used for wind and solar facilities were adjusted upward to match EPA assumptions that new wind and solar facilities will have capacity factors as high as 42.2 percent and 24.7 percent, respectively. These are generous assumptions because the current MISO-wide capacity factor of existing wind turbines is only 36 percent, and solar is 20 percent.

Our analysis upwardly adjusted observed capacity factors to EPA's estimates despite the fact that EPA's assumptions for onshore wind are significantly higher than observed capacity factors reported from Lawrence Berkeley National Labs, which demonstrates that new wind turbines entering operation since 2015 have never achieved annual capacity factors of 42.2 percent (See Figure D-12).[76]

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[75] Energy Information Administration, "Hourly Electric Grid Monitor," Accessed August 12, 2022, https://www.eia.gov/ electricity/gridmonitor/dashboard/electric_overview/balancing_authority/MISO

[76] Lawrence Berkely National Labs, "Wind Power Performance," Land Based Wind Report, Accessed July 27, 2023, https://emp.lbl.gov/wind-power-performance.

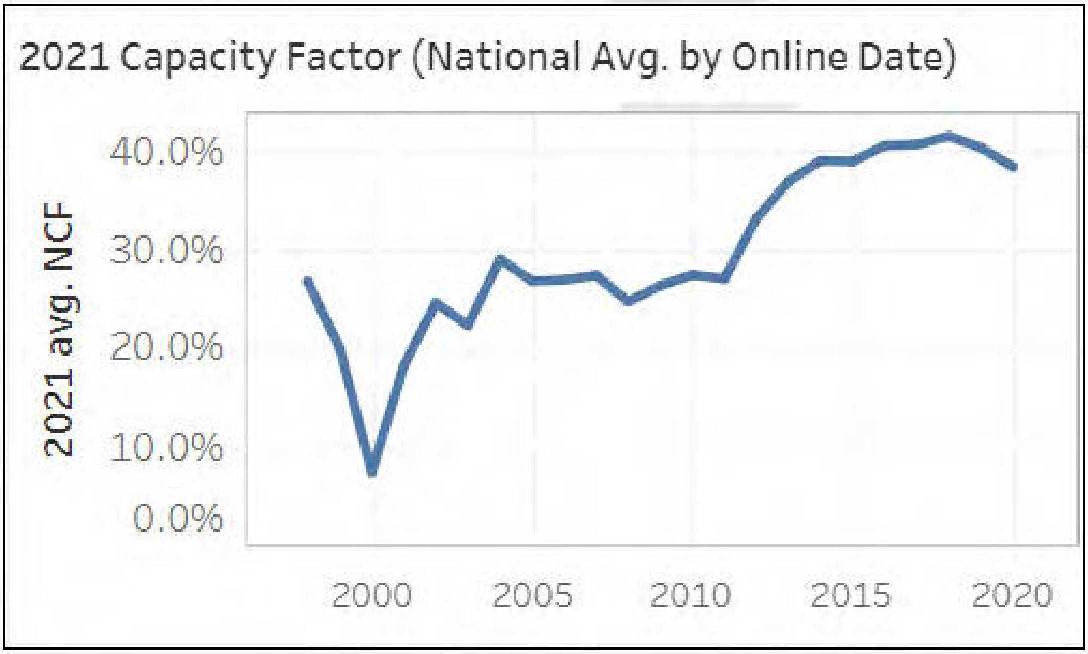

Figure D-12. This *figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 42.2 percent capacity factor on an annual basis.*

Another generous assumption is that we did not hold natural gas plants accountable to other EPA rules, such as the Carbon Rule, that may be in effect in addition to the MATS rule and would cap natural gas generators at 49 percent capacity factors to avoid using carbon capture and sequestration or co-firing with hydrogen. Doing so would have resulted in even more capacity shortfalls.

Line Losses

Line losses are assumed to be 5 percent of the electricity transmitted and distributed in the United States based on U.S. on EIA data from 2017 through 2021.[77]

Value of Lost Load

The value of lost load (VoLL) is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

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[77] Energy Information Administration, "How Much Electricity is Lost in Electricity Transmission and Distribution in the United States," Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

Our analysis uses a conservative midpoint estimate of $14,250 per MWh for VoLL. This value is higher than MISO's previous VoLL estimate of $3,500 per MWh, but significantly lower than the Independent Market Monitor's suggested estimate of $25,000 per MWh.[78]

Plant Retirement Schedules

Our modeling utilizes announced coal and natural gas retirement dates from U.S. EIA databases and announced closures in utility IRPs using a dataset collected by NERA economic consulting.

Plant Construction by Type

The resource adequacy and reliability portions of this analysis use MISO Interconnection Queue data to project into the future. EPA capacity values are applied to each newly constructed resource until the MISO system hits its target reserve margin based on EPA's peak demand forecast in its IPM.

Load Modifying Resources, Demand Response, and Imports

Our model allows for the use of 7,875 MW of Load Modifying Resources (LMRs) and 3,638 MW external resources (imports) in determining how much reliable capacity will be needed within MISO to meet peak electricity demand under the new MATS rules.

Utility Returns

Most of the load serving entities in MISO are vertically integrated utilities operating under the Cost-of-Service model. The amount of profit a utility makes on capital assets is called the Rate of Return (RoR) on the Rate Base. For the purposes of our study, the assumed rate of return is 9.9 percent with debt/equity split of 48.92/51.08 based on the rate of return and debt/equity split of the ten-largest investor-owned utilities in MISO.

Transmission

This analysis assumes the building of transmission estimated at $10.3 billion, which is consistent with MISO tranche 1 for the Status Quo Scenario. For the Full and Partial scenarios, transmission costs are estimated to be $223,913 per MW of new installed capacity to account for the increased wind, solar, storage, and natural gas capacity additions.

Taxes and Subsidies

Additional tax payments for utilities were calculated to be of 1.3 percent of the rate base. The state income tax rate of 7.3 percent was estimated by averaging the states within the MISO region. The

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[78] Potomac Economics, "2022 State of the Market Report for the MISO Electricity Markets," Independent Market Monitor for the Midcontinent ISO, June 15, 2023, https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

Federal income tax rate is 21 percent. The value of the Production Tax Credit (PTC) is $27.50. The Investment Tax Credit (ITC) 30 percent through 2032, 26 percent in 2033, and 22 percent in 2034.

Battery Storage

Battery storage assumes a 5 percent efficiency loss on both ends (charging and discharging).

Maximum discharge rates for the MISO system model runs were held at the max capacity of the storage fleet, less efficiency losses. Battery storage is assumed to be 4-hour storage, while pumped storage is assumed to be 8-hour storage.

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[79] However, our study does not take wind or solar degradation into account.

Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs for all new generating units are sourced from the EIA 2023 Assumptions to the Annual Energy Outlook (AOE) Electricity Market Module (EMM). These costs are held constant throughout the model run. Expenses for fixed and variable O&M for new resources were also obtained from the EMM. MISO region capital costs were used, and national fixed and variable O&M costs were obtained from Table 3 in the EMM report.[80]

Discount Rate

A discount rate of 3.76 percent is used in accordance with EPA's assumptions in the IPM.

Unit Lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account. Wind turbines are assumed to last for 20 years, solar panels are assumed to last 25 years, battery storage for 15 years. Natural gas plants are assumed to last for 30 years.

Repowering

Our model assumes wind turbines, solar panels, and battery storage facilities are repowered after they reach the end of their useful lives. Our model also excludes economic repowering, a growing

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[79] Liam Stoker, "Built Solar Assets Are 'Chronically Underperforming,' and Modules Degrading Faster than Expected, Research Finds," PV Tech, June 8, 2021, https://www.pv-tech.org/built-solar-assets-are-chronically-underperforming-andmodules-degrading-faster-than-expected-research-finds/.

[80] U.S. Energy Information Administration, "Electricity Market Module," Assumptions to the Annual Energy Outlook 2022, March 2022, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

trend whereby wind turbines are repowered after just 10 to 12 years to recapture the wind Production Tax Credit (PTC). This trend will almost certainly grow in response to IRA subsidies.

EPA does not appear to take repowering into consideration because the amount of existing wind on its systems never changes. If our understanding of EPA's methodology is accurate, this a large oversight that must be corrected.

Fuel Cost Assumptions

Fuel costs for existing power facilities were estimated using FERC Form 1 filings and adjusted for current fuel prices.[81,82] Fuel prices for new natural gas power plants were estimated by averaging annual fuel costs within the MISO region according to EPA.[83] Existing coal fuel cost assumptions of $17.82 per MWh were based on 2020 FERC Form 1 filings.

Inflation Reduction Act (IRA) Subsidies

Our analysis assumes all wind projects will qualify for IRA subsidies and elect the Production Tax Credit, valued at $27.50 per MWh throughout the model run. Solar facilities are assumed to select the Investment Tax Credit in an amount of 30 percent of the capital cost of the project.

Appendix 2: Capacity Retirements and Additions in Each Scenario

This section details the capacity additions and retirements in the MISO region under each scenario.

Status Quo scenario: The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. Additions in the Status Quo scenario consist of 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.

Annual retirement and additions can be seen in Figure D-13 below.

[81] Trading Economics, "Natural Gas," https://tradingeconomics.com/commodity/natural-gas.
[82] https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region
[83] U.S. Energy Information Administration, "Open Data," https://www.eia.gov/opendata/v1/qb.php?category=40694&sdid=SEDS.NUEGD.WI.A

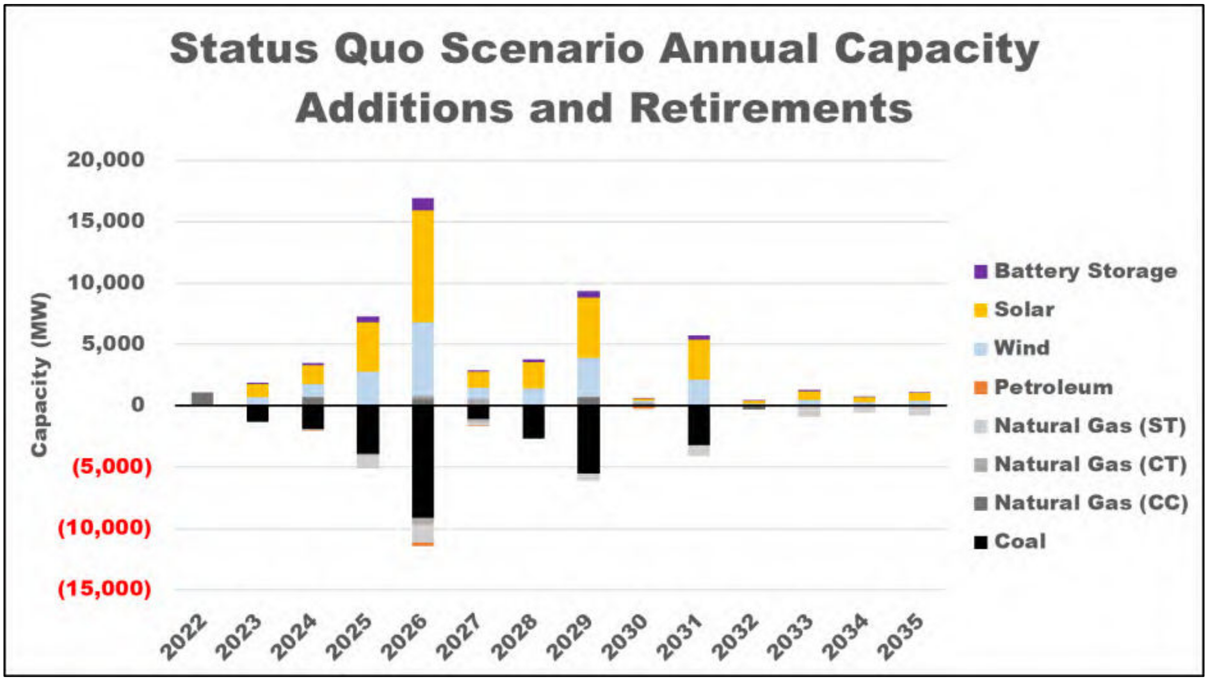


Figure D-13. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

Partial scenario: The Partial scenario results in the retirement of 29,908 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Partial scenario consist of 4,306 MW of natural gas, 20,451 MW of wind, 31,201 MW of solar, and 3,477 MW of storage (see Figure D-14). The incremental closure of 1,151 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage (see Figure D-15).[84]

[84] Replacement capacity is more than the retiring 1,151 MW of coal capacity because intermittent resources like wind and solar have lower capacity values than coal capacity.

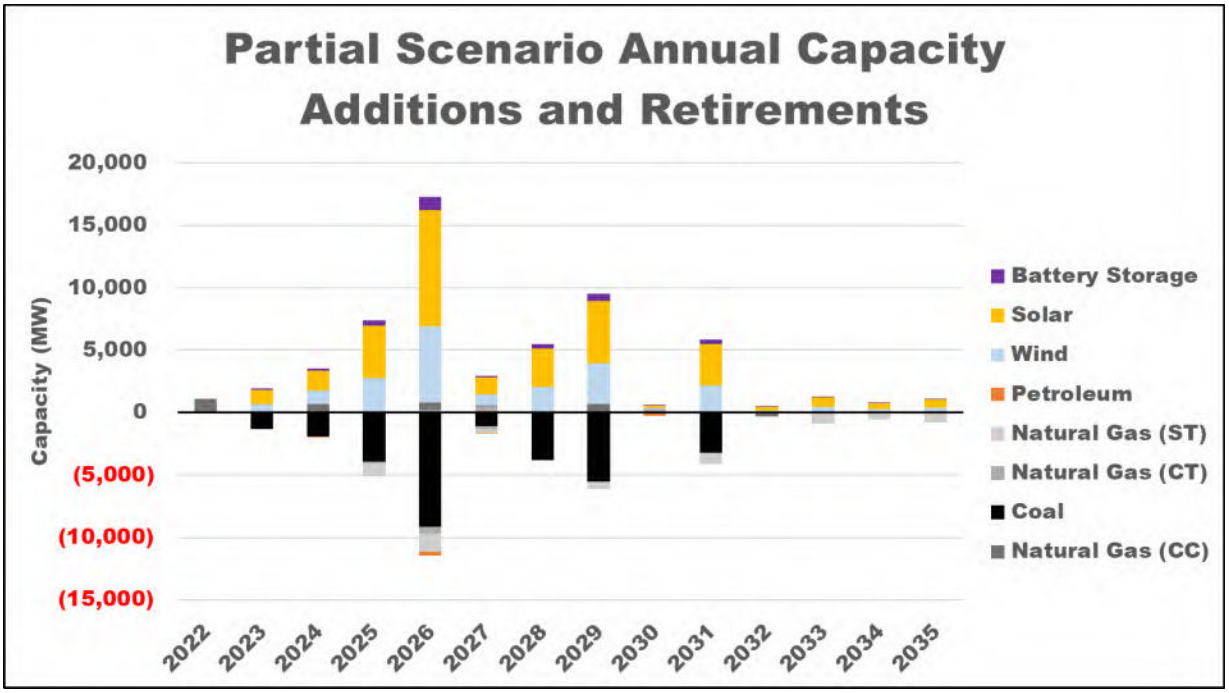


Figure D-14. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

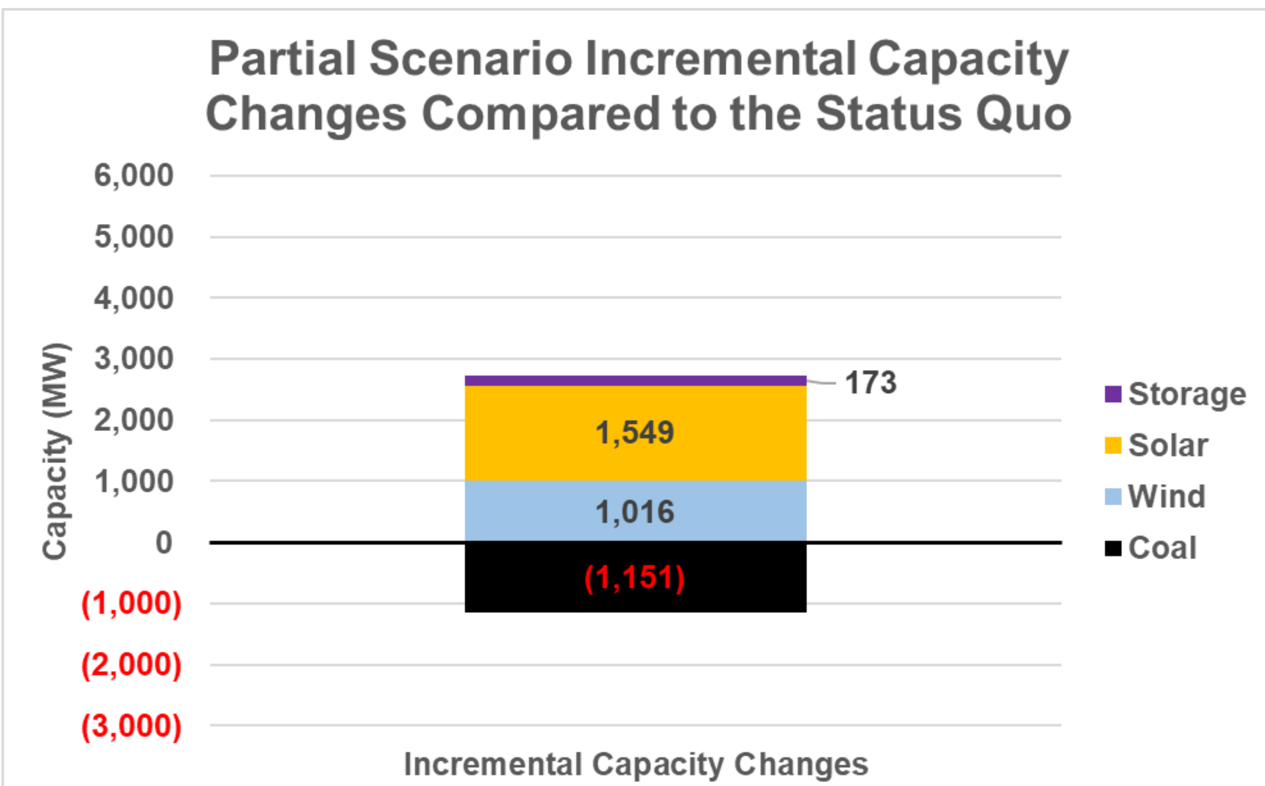


Figure D-15. This figure shows the incremental capacity retirements and additions in the MISO region under the Partial scenario.

Full Scenario: The Full scenario results in the retirement of 31,021 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Full scenario consist of 4,306 MW of natural gas, 21,433 MW of wind, 32,700 MW of solar, and 3,644 MW of storage (see Figure D-16). The incremental closure of 2,264 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage, compared to the Status Quo scenario (see Figure D-17).

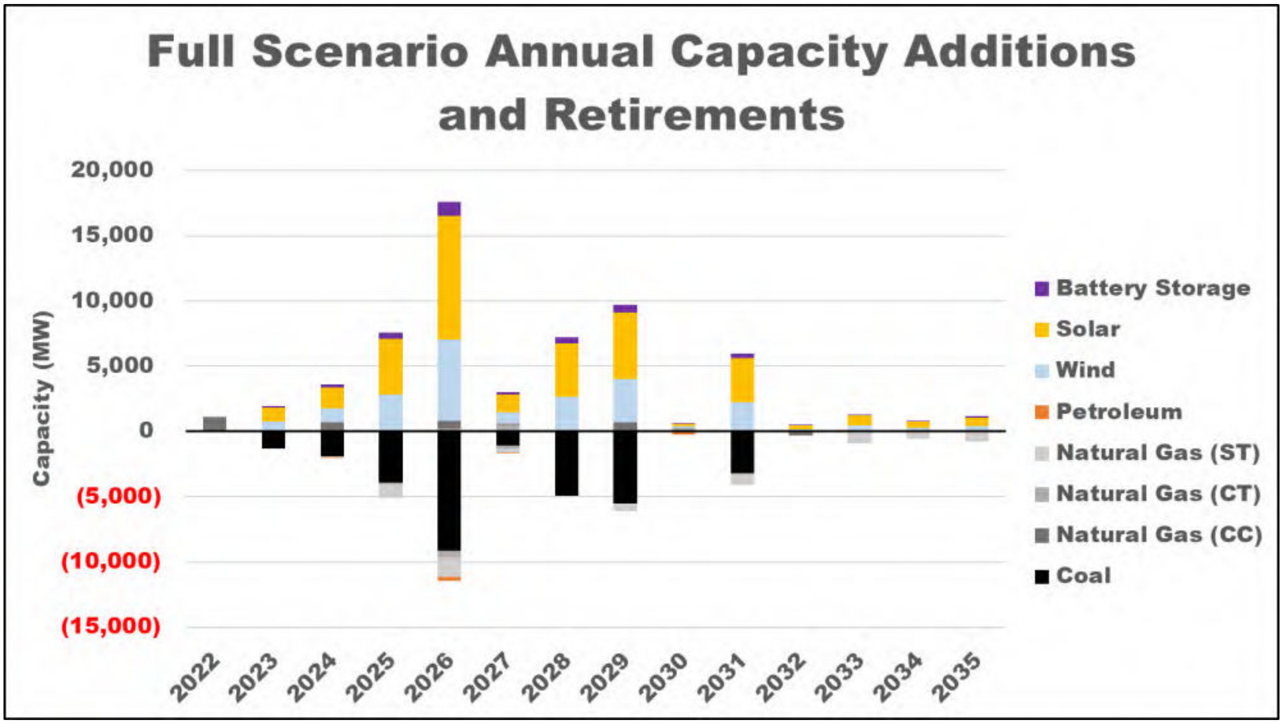


Figure D-16. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

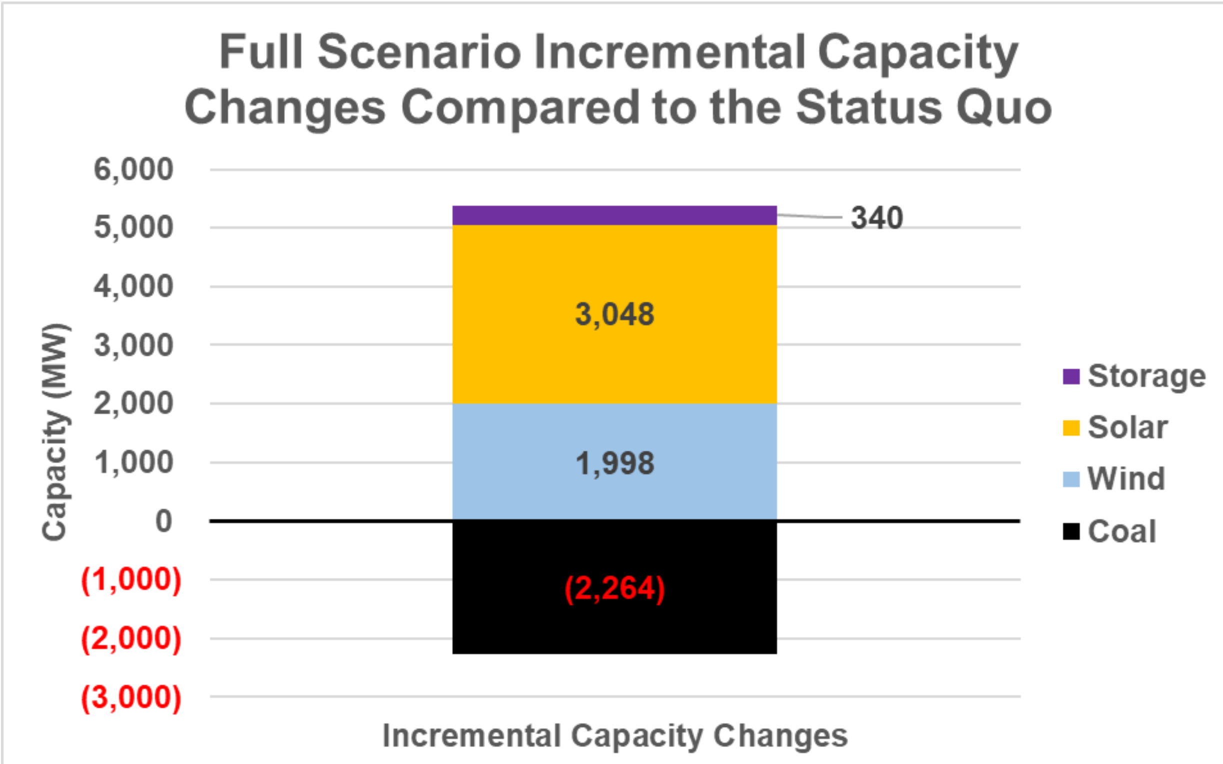


Figure D-17. This figure shows the incremental capacity closures and additions in the Full scenario.

Figure D-18 shows the capacity retirements and additions in the Partial and Full scenarios.

Comparison:

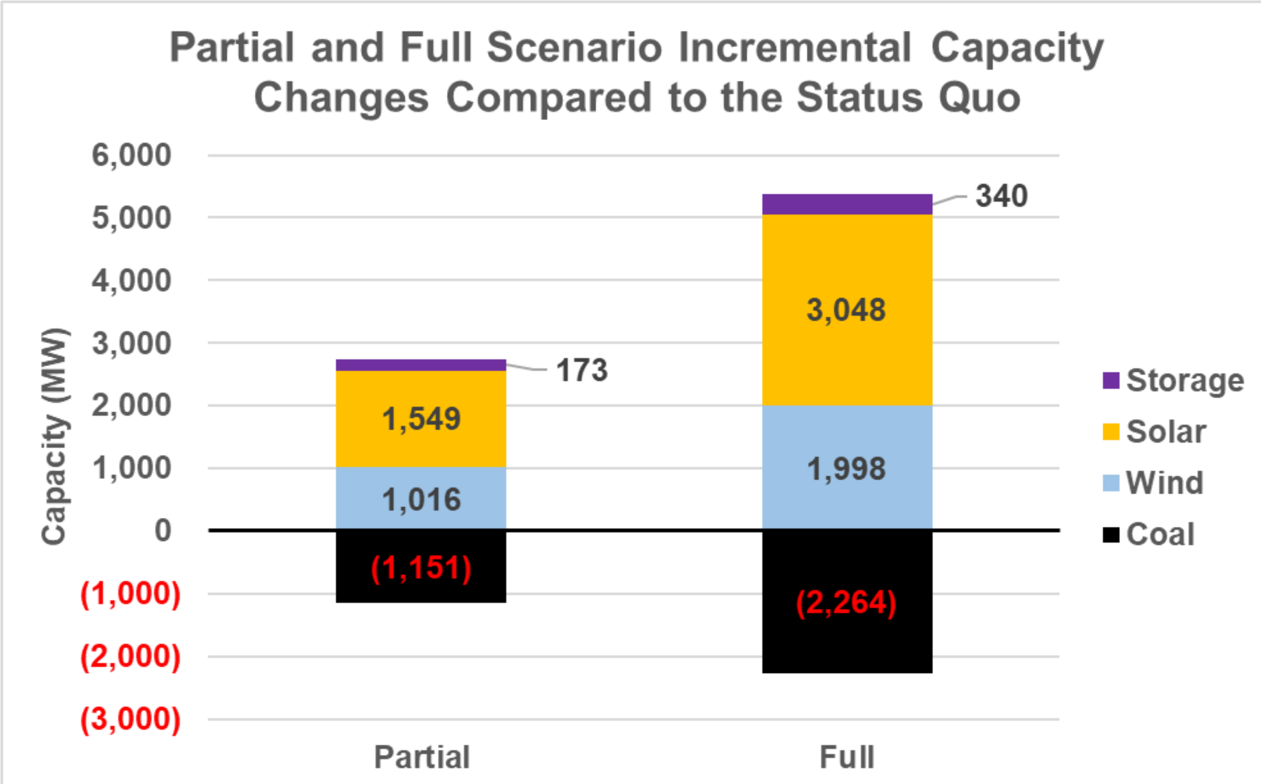


Figure D-18 comparison. This figure demonstrates the incremental retirements and additions in each scenario.

Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy

The capacity selected in our model to replace the retiring resources is based on two main factors. The first factor is the MISO interconnection queue, which is predominantly filled with solar and wind projects and a relatively small amount of natural gas. The second factor is the EPA's resource adequacy (RA) accreditation values in the Integrating Planning Model's (IPM) Proposed Rule Supply Resource Utilization file and Post-IRA Base Case found in the Regulatory Impact Analysis.

The IMP assumes a capacity accreditation of 100 percent for thermal resources, and variable intermittent technologies (primarily wind and solar) receive region-specific capacity credits to help meet target reserve margin constraints. Due to their variability, resources such as wind and solar received a lower capacity accreditation when solving for resource adequacy (see Table D-4).

EPA Integrated Planning Model

Capacity Accreditation in MISO

Resource	Capacity Value
Existing Wind	19%
Existing Solar	55%
New Onshore Wind 2035	17%
New Solar 2035	52%
Thermal	100%
Battery Storage	100%

Table D-4. This figure shows the capacity values for each resource based on EPA's estimates in its IPM.

In order to determine whether the available blend of power generation sources will be able to meet projected demand, each available generation source is multiplied against its capacity value, and the available resources are then "stacked" to determine if there is enough accredited power generation capacity to meet projected demand and maintain resource adequacy.

It should be noted that EPA's accreditation values from the IPM are generous compared to the accreditation values given by RTOs. For example, in the MISO region, grid planners assume that dispatchable thermal resources like coal, natural gas, and nuclear power plants will be able to produce electricity 90 percent of the time when the power is needed most, resulting in a UCAP rating of 90 percent. In contrast, MISO believes wind resources will only provide about 18.1 percent of their potential output during summer peak times, and solar facilities will produce 50 percent of their potential output. This report uses the generous capacity values provided by EPA; however, if the capacity values used by the RTOs were to be utilized, the projected energy shortfalls and blackouts would be even worse.

Appendix 4: Resource Adequacy in Each Scenario

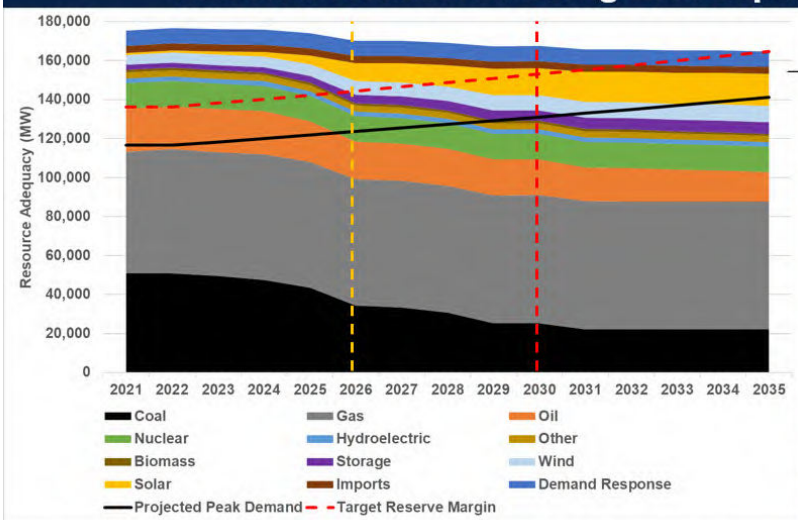
We performed a Resource Adequacy analysis on each of the three scenarios modeled to determine the potential impact to grid reliability in MISO region if implementation of the MATS Rule results in the forced retirement of lignite power plants.

Status Quo scenario

Under the Status Quo scenario, there is enough dispatchable capacity in MISO to meet the projected peak demand and target reserve margin established by EPA in the RIA documents

Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-19.[85]

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage, and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

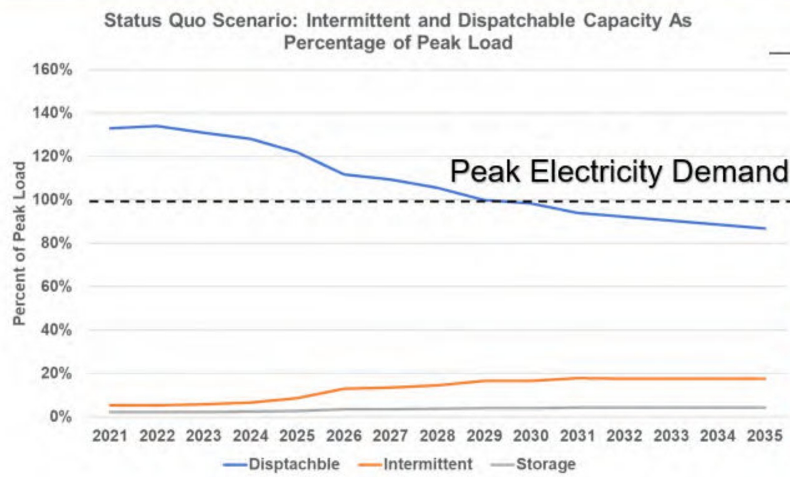
Figure D-19. By 2030, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

Beginning in 2026, MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin, but the RTO still has enough dispatchable capacity to meet its projected peak demand. By 2030, the MISO region will rely on thermal resources and 4-hour battery storage to meet its peak demand, and by 2031 the region will no longer have enough dispatchable capacity or storage to meet its projected peak demand, and it will rely exclusively on non-dispatchable resources and imports to meet its target reserve margin.[86]

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-20 below. By 2035, dispatchable capacity consisting of thermal generation and battery storage will only be able to provide 91 percent of the projected peak demand, necessitating the use of wind and solar to maintain resource adequacy.

[85] Analysis of the Proposed MATS Risk and Technology Review (RTR) | US EPA, https://www.epa.gov/power-sector-modeling/analysis-proposed-mats-risk-and-technology-review-rtr
[86] While battery storage is considered dispatchable in this analysis for the sake of simplicity, battery resources are not a substitute for generation because as grids become more reliant upon wind and solar, battery resources may not be sufficiently charged to provide the needed dispatchable power.

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

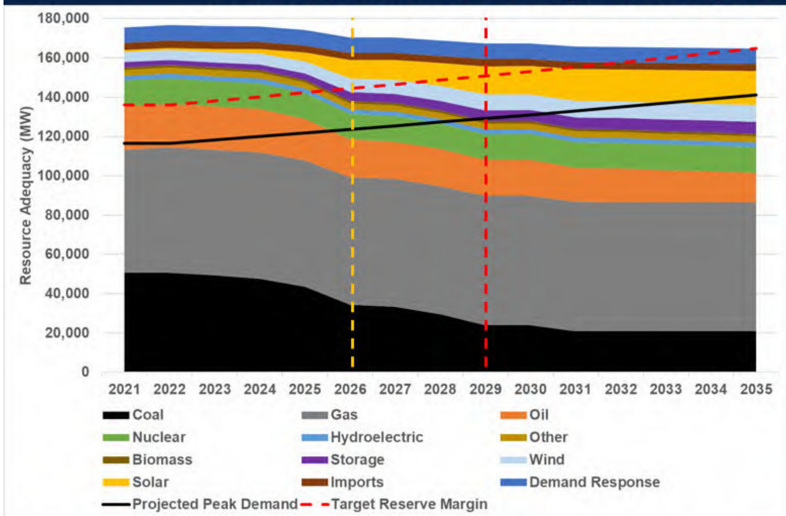
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

D-20. By 2035, dispatchable generators will only constitute 87 percent of projected peak demand, with storage accounting for four percent of peak demand capacity.

Partial scenario

Like the Status Quo Scenario, there is enough dispatchable capacity in MISO under the Partial scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-21.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

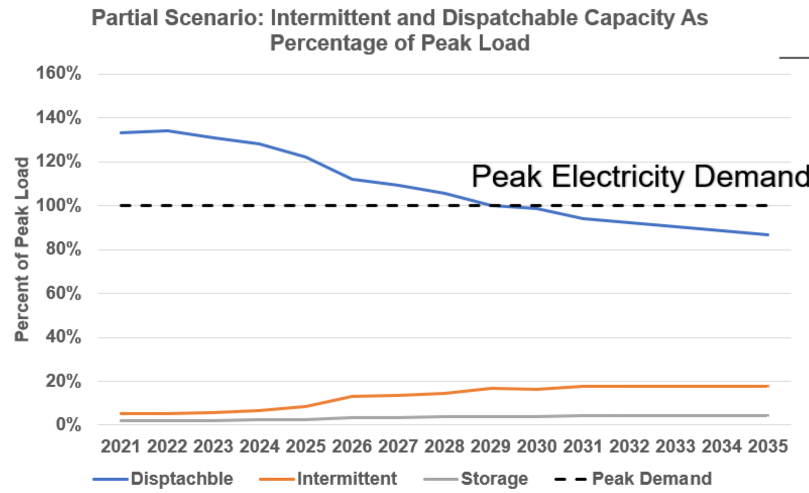
Figure D-21. By 2029, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 105 percent in the Partial scenario, reflecting the loss of 1,151 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports, or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-22 below. By 2035, dispatchable capacity will only be able to provide 86 percent of the projected peak demand.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

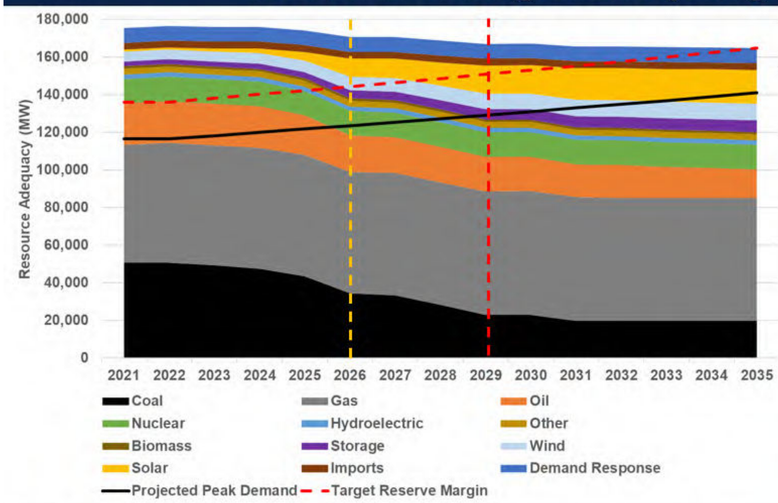
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-22. The percentage of peak electricity demand being served by dispatchable resources drops by one percent in 2028, relative to the Status Quo scenario, due to the closure of lignite capacity in MISO due to the MATS rule.

Full scenario

Like the Status Quo scenario and Partial scenario, there is enough dispatchable capacity in MISO under the Full scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-23.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

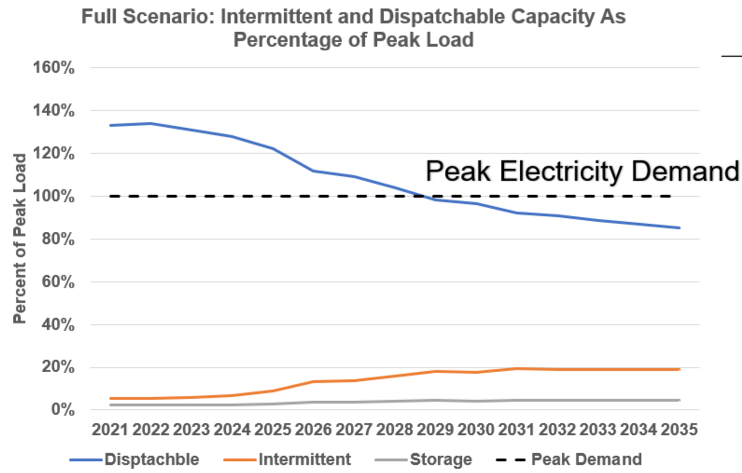
Figure D-23. The amount of dispatchable capacity available to meet projected peak demand in 2028 falls from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the closure of all the lignite capacity in MISO that year.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the loss of 2,264 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-24 below. By 2035, dispatchable capacity will only be able to provide 85 percent of the projected peak demand, a two percent decline relative to the Status Quo scenario, necessitating the use of wind and solar to maintain resource adequacy.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-24. The amount of peak demand that can be met with dispatchable resources in 2028 falls from 106 in the Status Quo scenario to 104 in the Full scenario.

Attachment B

to the Declaration of Christopher D. Friez

NDSU Agribusiness and Applied Economics Report No. 819-S March 2023

North Dakota Lignite Energy Industry

Economic Contribution Analysis

Report Content

Preface

This report is the latest biennial assessment of the economic contribution of the North Dakota lignite energy industry.

Data for this study came from industry surveys, state and federal agencies, and other secondary sources,

The definition of the lignite energy industry and methods used to estimate its economic contribution are consistent with studies examining the economic contribution of other industries in the state. As usual, these studies are snapshots in time and economic contributions often vary from year to year with commodity-based industries.

Industry Highlights

The following figures are based on activity during 2021 and projections of industry output in 2022. All values include direct and secondary economic effects.

North Dakota Lignite Energy Industry in 2021

- $5.64 billion gross business volume
  - $0.9 billion from mining
  - $3.2 billion from coal conversion and electricity generation
  - $1.5 billion from transmission/distribution
- 12,800 jobs (direct and secondary)
  - 3,300 jobs supported by mining
  - 8,400 jobs supported by coal conversion and electricity generation
  - 1,050 jobs supported by transmission/distribution
- $119 million in local and state government revenues

North Dakota Lignite Energy Industry in 2022

- $5.75 billion gross business volume
  - $0.8 billion from mining
  - $3.2 billion from coal conversion and electricity generation
  - $1.7 billion from transmission/distribution
- 12,000 jobs (direct and secondary)
  - 3,250 jobs supported by mining
  - 7,725 jobs supported by coal conversion and electricity generation
  - 1,060 jobs supported by transmission/distribution
- $104 million in local and state government revenues

**Bangsund is a Research Scientist, Department of Agribusiness and Applied Economics and Hodur is Director, Center for Social Research, North Dakota State University

Understanding the Numbers

Economic contribution assessments measure the gross size of an industry or economic sector.

Size is estimated by combining ***direct*** or first-round effects (i.e., sales, spending, and/or employment) with economic modeling to estimate secondary effects of business-to-business transactions (***indirect***) and household spending for goods and services (***induced***).

Economic measures frequently used in economic contribution assessments:

- **Labor income** – earnings of workers and sole proprietors
- **Employment** – wage and salary jobs and sole proprietor/self-employed jobs
- **Gross business volume** – includes direct sales of products and services of the industry being measured, and sum of all business-to-business and household-to-business transactions associated with indirect and induced economic activity
- **Value-added** – represents share of gross state product

An overview and additional information on study methods, data sources, and economic definitions are appended to the end of this report.

Composition of Lignite Energy Industry

Coal Mining: this segment involves the process of extracting lignite coal and delivering it to conversion facilities.

Coal Gasification: this segment involves converting lignite coal into chemicals and other products. It is grouped with electricity generation segment of the industry.

Electricity Generation: this segment burns lignite coal to produce electricity.

Transmission and Distribution: this segment includes moving electricity to local (in-state) distributors and exporting electricity to out-of-state markets.

Industry Contribution 2021

Coal mining had 1,131 direct jobs; business activity relating to coal mining operations supported another 1,220 jobs. Personal spending on goods and services by employees working in the coal mining sector and employees of businesses affected by coal mining supported an additional 960 jobs. The combined effects on statewide employment from coal mining was estimated at 3,300 jobs. Other economic effects from coal mining included $300 million in labor income and $915 million in gross business volume.

Coal conversion and electricity generation from lignite was estimated to have nearly 1,700 direct jobs, and business activity relating to those lignite operations supported another 4,680 jobs. Personal spending on goods and services by employees working in the coal conversion and generation activities and employees of businesses affected by those activities supported an additional 2,070 jobs. The combined direct, indirect, and induced effects on statewide employment from coal conversion and electricity generation was estimated at 8,400 jobs. Other economic effects from coal conversion and electricity generation included $670 million in labor income and nearly $3.2 billion in gross business volume.

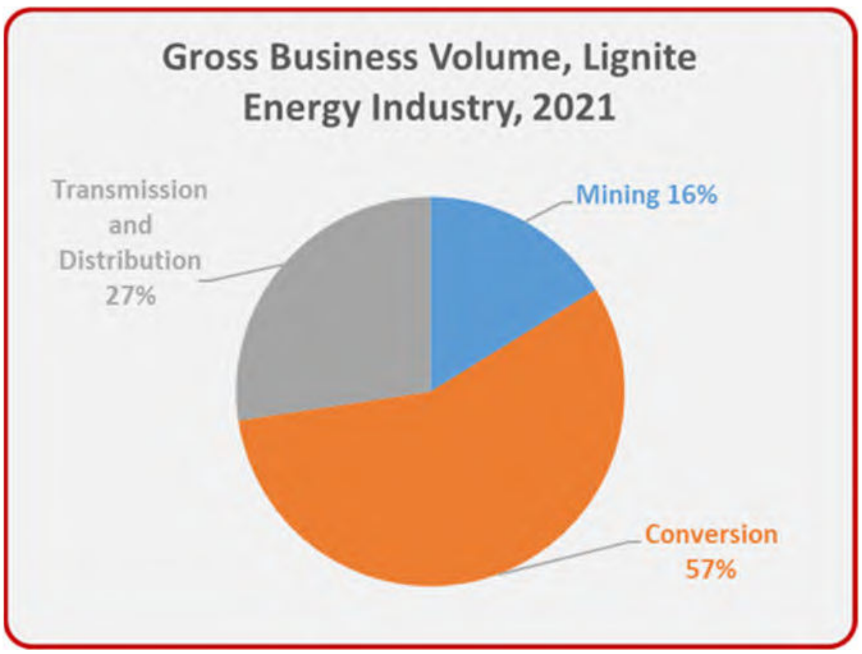
Electricity transmission and generation from lignite-based activities was estimated to have 480 direct jobs; business activity relating to those lignite operations supported another 290 jobs. Personal spending on goods and services by employees working in coal-related electricity transmission and distribution and employees of businesses affected by those activities supported an additional 280 jobs. The combined direct, indirect, and induced effects on statewide employment from coal-related electricity transmission and distribution was estimated at 1,060 jobs. Other economic effects from transmission and distribution included $84 million in labor income and $1.5 billion in gross business volume.

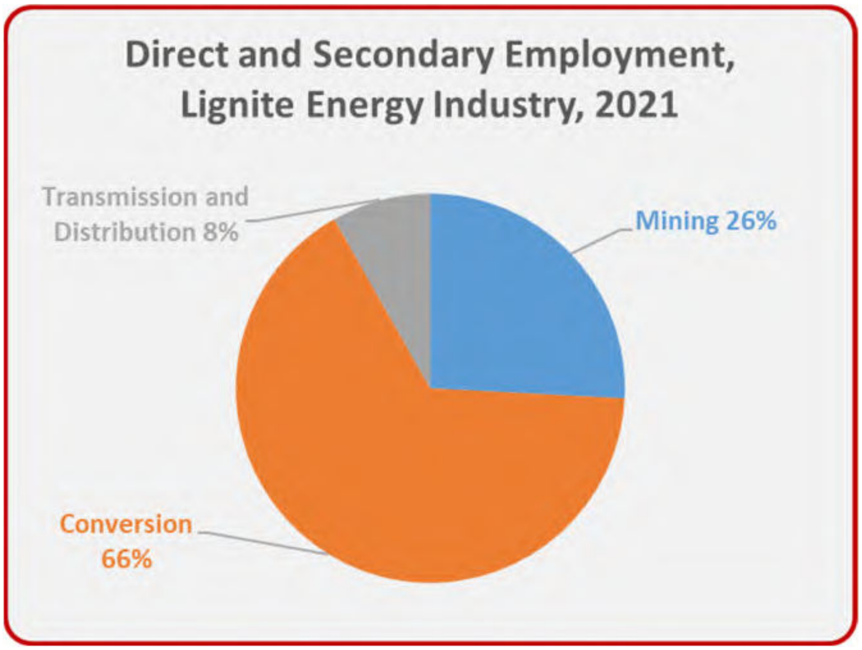
The combination of coal mining, coal conversion, coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,300 direct jobs in North Dakota in 2021. These lignite coal activities supported about 6,190 jobs through business purchases of goods and services in the state. The combined personal spending of employees in the Lignite Industry, and employees of businesses involved with supplying goods and services to the industry supported another 3,310 jobs. Collectively, the industry was estimated to support 12,800 jobs in the state.

The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income. The industry also contributed $2 billion to the state's gross domestic product, and the industry's gross business volume was estimated at $5.6 billion.

Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2021				
Industry Segment/Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
Coal Mining		-------------------- millions 2021 $	--------------------	
Direct effects	1,131	165	227	560
Indirect effects	1,220	84	152	270
Induced effects	960	51	84	85
Total economic effects	3,311	300	463	915
Electricity Generation and Coal Conversion				
Direct effects	1,694	228	240	1,728
Indirect effects	4,680	332	568	1,120
Induced effects	2,070	110	182	331
Total economic effects	8,444	671	990	3,178
Electricity Transmission and Distribution				
Direct effects	483	50	453	1,386
Indirect effects	290	19	69	111
Induced effects	285	15	25	45
Total economic effects	1,058	84	547	1,543

[1] Employment represents total jobs, and does not represent employment in FTE.





Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2021				
Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
ND Lignite Industry		-------------------- millions 2021 $	--------------------	
Direct	3,308	443	919	3,674
Indirect	6,190	436	789	1,501
Induced	3,310	177	291	461
Total	**12,808**	**1,056**	**1,999**	**5,636**

[1] Employment represents total jobs, and does not represent employment in FTE.

Industry Contribution 2022 (projected)

The following figures and values were based on an industry survey soliciting estimates of calendar year 2022 business activities, although the survey was administered prior to yearend. Firms were asked to estimate what their 2022 revenues and expenditures would be based on data available at the time of the survey and augment that information with expected activities for the remaining months in 2022. Data provided by the industry for 2022 is treated as a projection. However, the projection is considered a reasonable estimate of 2022 since, in many cases, the estimates included actual revenues and expenditures for 10 to 11 months of 2022.

Coal mining had 1,170 direct jobs; business activity relating to coal mining operations supported another 1,090 jobs. Personal spending on goods and services by employees working in the coal mining sector and employees of businesses affected by coal mining supported an additional 990 jobs. The combined effects on statewide employment from coal mining was estimated at 3,250 jobs. Other economic effects from coal mining included $300 million in labor income and $830 million in gross business volume.

Coal conversion and electricity generation from lignite was estimated to have 1,630 direct jobs, and business activity relating to those lignite operations supported another 4,240 jobs. Personal spending on goods and services by employees working in the coal conversion and generation activities and employees of businesses affected by those activities supported an additional 1,850 jobs. The combined direct, indirect, and induced effects on statewide employment from coal conversion and electricity generation was estimated at 7,720 jobs. Other economic effects from coal conversion and electricity generation included $620 million in labor income and over $3.2 billion in gross business volume.

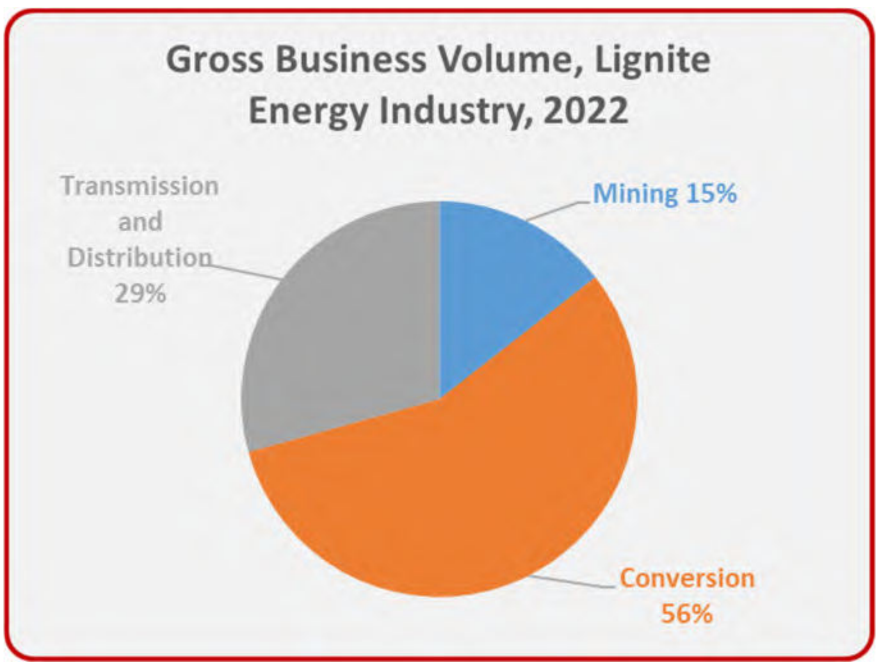
Electricity transmission and generation from lignite-based activities was estimated at 470 direct jobs; business activity relating to those lignite operations supported another 300 jobs. Personal spending on goods and services by employees working in coal-related electricity transmission and distribution and employees of businesses affected by those activities supported an additional 280 jobs. The combined direct, indirect, and induced effects on statewide employment from coal-related electricity transmission and distribution was estimated at 1,050 jobs. Other economic effects from transmission and distribution included $86 million in labor income and $1.7 billion in gross business volume.

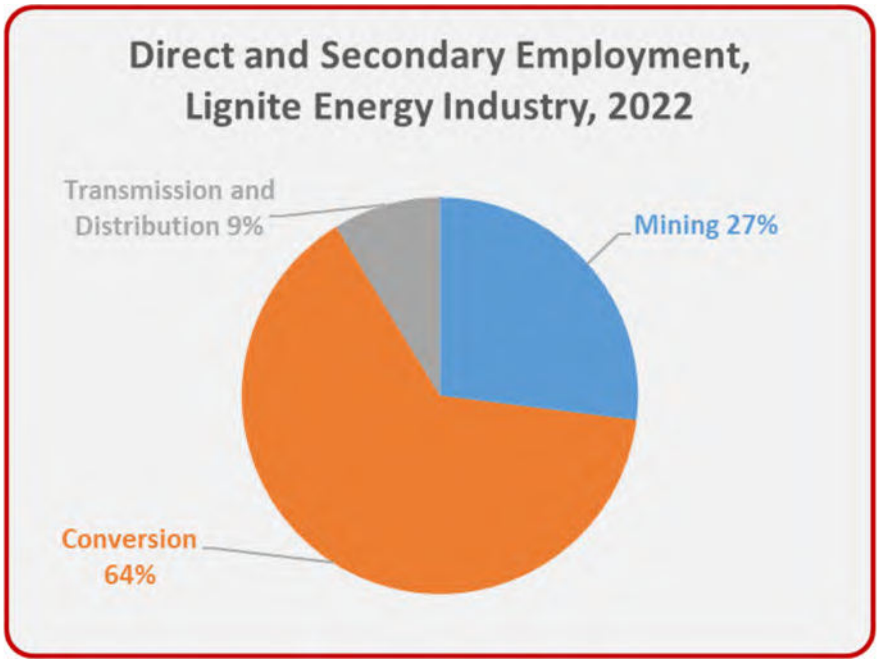
The combination of coal mining, coal conversion, lignite coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,270 direct jobs in North Dakota in 2022. These lignite coal activities supported about 5,630 jobs through business purchases of goods and services in the state. The combined personal spending of employees in the Lignite Industry, and employees of businesses involved with supplying goods and services to the industry supported another 3,120 jobs. Collectively, the industry was estimated to support 12,020 jobs in the state.

The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income. The industry also contributed nearly $2.2 billion to the state's gross domestic product, and the industry's gross business volume was estimated at $5.8 billion.

Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, Projected 2022				
Industry Segment/Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
Coal Mining		---------------------- millions 2022 $	----------------------	
Direct effects	1,168	177	219	537
Indirect effects	1,090	76	123	207
Induced effects	990	53	87	88
Total economic effects	3,248	306	430	832
Electricity Generation and Coal Conversion				
Direct effects	1,633	225	510	2,008
Indirect effects	4,240	295	534	935
Induced effects	1,850	99	163	297
Total economic effects	7,723	619	1,208	3,239
Electricity Transmission and Distribution				
Direct effects	473	51	473	1,525
Indirect effects	300	20	47	116
Induced effects	280	15	25	45
Total economic effects	1,053	86	545	1,687

[1] Employment represents total jobs, and does not represent employment in FTE.





Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2022 (projected)

Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
ND Lignite Industry		--------------------	millions 2022 $	--------------------
Direct	3,274	453	1,202	4,070
Indirect	5,630	391	704	1,258
Induced	3,120	167	275	430
Total	**12,024**	**1,011**	**2,182**	**5,758**

[1] Employment represents total jobs, and does not represent employment in FTE.

Government Revenues 2021

Government revenues are often used as a measure of how effectively an industry supports public services. In North Dakota, the most common sources of in-state public revenues are severance taxes, sales and use taxes, property taxes, and income taxes. A host of other taxes and revenue sources are often tracked in economic contribution and impact assessments, but those sources have varying levels of contribution to government revenue.

The lignite industry was estimated to contribute $64.5 million in government revenues directly from the firms in the industry. Tax revenues arising from secondary business activity were estimated to generate an additional $54.5 million in state and local government revenues. A total of $119 million in state and local tax revenues were generated by the Lignite Industry in North Dakota in 2021.

Coal conversion and coal severance taxes were estimated at $26.5 million. Other substantial contributions to state and local government revenues from secondary economic effects were from sales taxes ($25 million) and property taxes ($19.5 million).

State and Local Government Revenues, Lignite Industry, North Dakota, 2021

Government Revenue	Paid Directly by the Industry	Collected from Indirect and Induced Activity	Total Collections
	---------------------- 000s 2021 $ ----------------------		
Coal Severance Tax	10,518	---	10,518
Coal Conversion Tax	15,991	---	15,991
Sales, Property, and Corporate Income Taxes (reported in survey data)	25,861	---	25,861
Social Insurance Tax	1,952	1,247	3,200
Personal Income Tax	3,039	2,377	5,416
Sales Tax	see above	25,336	25,336
Property Tax	see above	19,531	19,531
Corporate Income Tax	see above	1,362	1,362
Other Taxes	2,666	1,438	4,104
Non Taxes	4,568	3,222	7,789
Totals	**64,595**	**54,512**	**119,107**

Government Revenues 2022 (projected)

The lignite industry was projected to contribute $53 million in government revenues directly from the firms in the industry. Tax revenues arising from secondary business activity, based on projections of industry activity, were estimated to generate an additional $50.6 million in government revenues. A projected total of $103.5 million in state and local tax revenues were created by the Lignite Industry in North Dakota in 2022.

Coal conversion and coal severance taxes were estimated at $15.8 million. Other substantial contributions to state and local government revenues from secondary economic effects were from sales taxes ($23.5 million) and property taxes ($18 million).

State and Local Government Revenues, Lignite Industry, North Dakota, 2022 (projected)

Government Revenue	Paid Directly by the Industry	Collected from Indirect and Induced Activity	Total Collections
	---------------------- 000s 2022 $	-----------------------	
Coal Severance Tax	10,450	---	10,450
Coal Conversion Tax	5,360	---	5,360
Sales, Property, and Corporate Income Taxes (reported in survey data)	25,667	---	25,667
Social Insurance Tax	1,996	1,183	3,179
Personal Income Tax	3,107	2,264	5,371
Sales Tax	see above	23,457	23,457
Property Tax	see above	18,082	18,082
Corporate Income Tax	see above	1,310	1,310
Other Taxes	2,349	1,331	3,680
Non Taxes	4,024	3,003	7,027
Totals	**52,953**	**50,630**	**103,583**

Share of State Economy

A key means of placing an industry contribution study into context is showing its share of a broader economy. The lignite energy industry represents an important share of the North Dakota's economy. The lignite energy industry represented 2.6 percent of the state's gross state product and 4 percent of the state's gross business volume. The industry represented about 2.8 percent of the state's total labor income. The industry represents about 1.2 percent of all state and local government revenues.

The lignite energy industry share of employment was 2.3 percent of statewide employment. Those shares are based on a state total for both wage and salary jobs and sole proprietors/self employed jobs. The industry's share of the state economy was not estimated for 2022 as state-level data was unavailable prior to completing the study.

ANNUAL SHARE OF STATE TOTALS, North Dakota Lignite Energy Industry

Industry Segment	Labor Income	Value-added (GSP)	Total Output	State and Local Government Revenues
State-level Values for 2021	$37.3 billion	$77.0 billion	$142.7 billion	$9.954 billion
Mining	0.81%	0.60%	0.64%	---
Conversion	1.80%	1.29%	2.23%	---
Transmission and Distribution	0.23%	0.71%	1.08%	---
All Segments	2.83%	2.60%	3.95%	1.20%

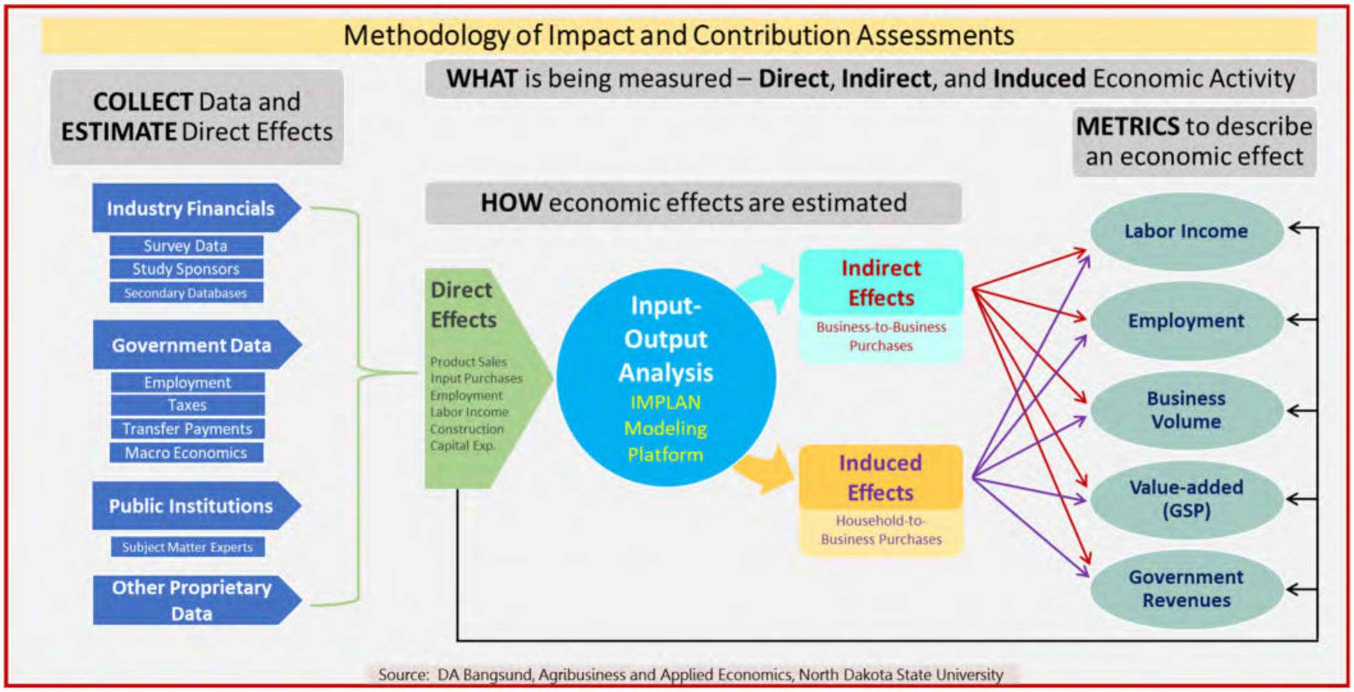
ANNUAL SHARE OF STATE EMPLOYMENT, North Dakota Lignite Energy Industry

Industry Segment	Total Employment	Wage and Salary	Self-employed
State-level Values for 2021	557,702	434,811	122,691
Mining	0.59	3184#	3175#
Conversion	1.51	31<<#	31;9#
Transmission and Distribution	0.19	314:#	313;#
		#	#
All Segments	2.30%	419:(#	4169(#

Supplemental Materials

Economic Contribution Analysis

An economic contribution assessment measures the gross size of some aspect or component of an economy, and is usually measured in conjunction with the overall size of a given economy over a specified period. Size is estimated by combining direct or first-round effects (e.g., industry expenditures, business sales, new employment) with economic modeling to estimate how those first round effects generate business-to-business transactions and household spending on consumer goods and services. Both of those conduits for economic output can be framed using labor income, employment, value-added, gross business volume and government revenues.



Key Terms and Concepts

Direct Effects: First-round of payments for services, labor, and materials and/or sales of an industry's products.

Indirect Effects: Economic activity created through purchases of goods and services by businesses.

Induced Effects: Economic activity created through purchases of goods and services by households.

Industry Output and Gross Business Volume: Industry output is the value of all goods and services produced and supported by an industry. In most industries, output is largely synonymous with sales; however, for some sectors output also includes changes in product inventory. For lignite energy industry, direct output includes both sales and inventory adjustments.

When output from business-to-business transactions (*indirect*) and households-to-businesses (*induced*) are measured, they also are described as the *sum of gross receipts* as annual adjustments to inventories are largely unquantified and not distinguished from sales. *Gross business volume* (GBV) therefore includes direct output/sales and includes secondary sales from indirect and induced economic activity.

Value-added: Value-added is synonymous with measures of gross domestic product (GDP) and gross state product (GSP), are some of the most commonly used economic measures to indicate the economic size and change in economic output. However, official government estimates of GDP and GSP do not include secondary economic effects generated by any industry. For lignite energy industry, official government estimates are primarily limited to coal mining, coal conversion, and transmission/distribution. Economic contribution assessments include secondary economic effects, and include GSP from those effects, thereby providing a more realistic and representative portrait of an industry.

Key components of value-added include labor income, consumption of fixed capital, profits, business current transfer payments (net), and income derived from dividends, royalties, and interest. In nontechnical terms, value-added is equal to product value minus production inputs. For example, value-added from coal mining would be the value of coal sold less the value of the inputs consumed in mining the coal. Depreciation charged to durable assets (e.g., buildings, pipelines, processing equipment) are not included in value-added measures.

Employment Compensation: Wages, salaries, and benefits earned by an employee.

Proprietor Income: Payments received by self-employed individuals and unincorporated business owner/operators.

Labor Income: Wages, salaries, and benefits for employees and compensation for self-employed individuals.

Input-output Analysis (I-O): Mathematical application of the interdependence among producing and consuming sectors in an economy.

I-O Matrix: Depiction of an economy using a grid of rows and columns that represents consumption and production for each economic sector in an economy.

Intermediate Inputs: Goods and services consumed in one year to produce another good or service. Intermediate inputs do not include expenditures for capital inputs used for multiple production seasons (e.g., machinery, buildings).

Capital Inputs: Represent the use of inputs to produce another good or service that are not consumed in one production season and are subject to depreciation. *Capital expenditures* represent the purchase of those depreciable assets.

Industry Balance Sheet: Dividing an industry or economic sector into various components for use in estimating the economic effects using input-output analysis. Components of the balance sheet include measures of output, wage and salary employment, self-employment, payroll and proprietor income, other property type income, taxes on production and imports, and intermediate inputs.

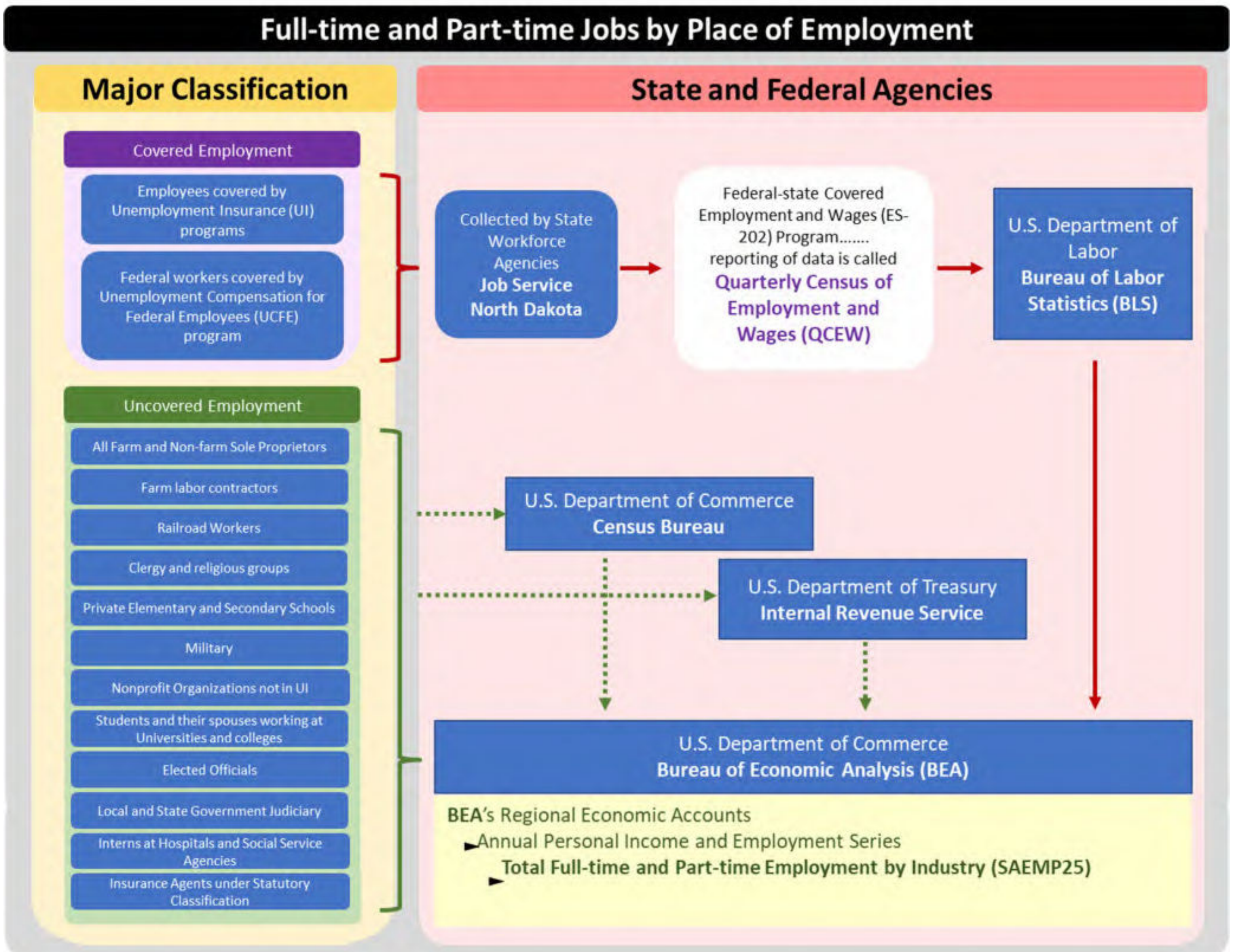
Institutions: Represent governments and other non-private entities consuming goods and services in an economy.

Households: Represent one or more individuals in a specific living arrangement for which income from all sources is used to purchase goods and services.

North American Industry Classification System (NAICS): Government classification system for all goods and services produced in the economy.

Employment Sources and Measures

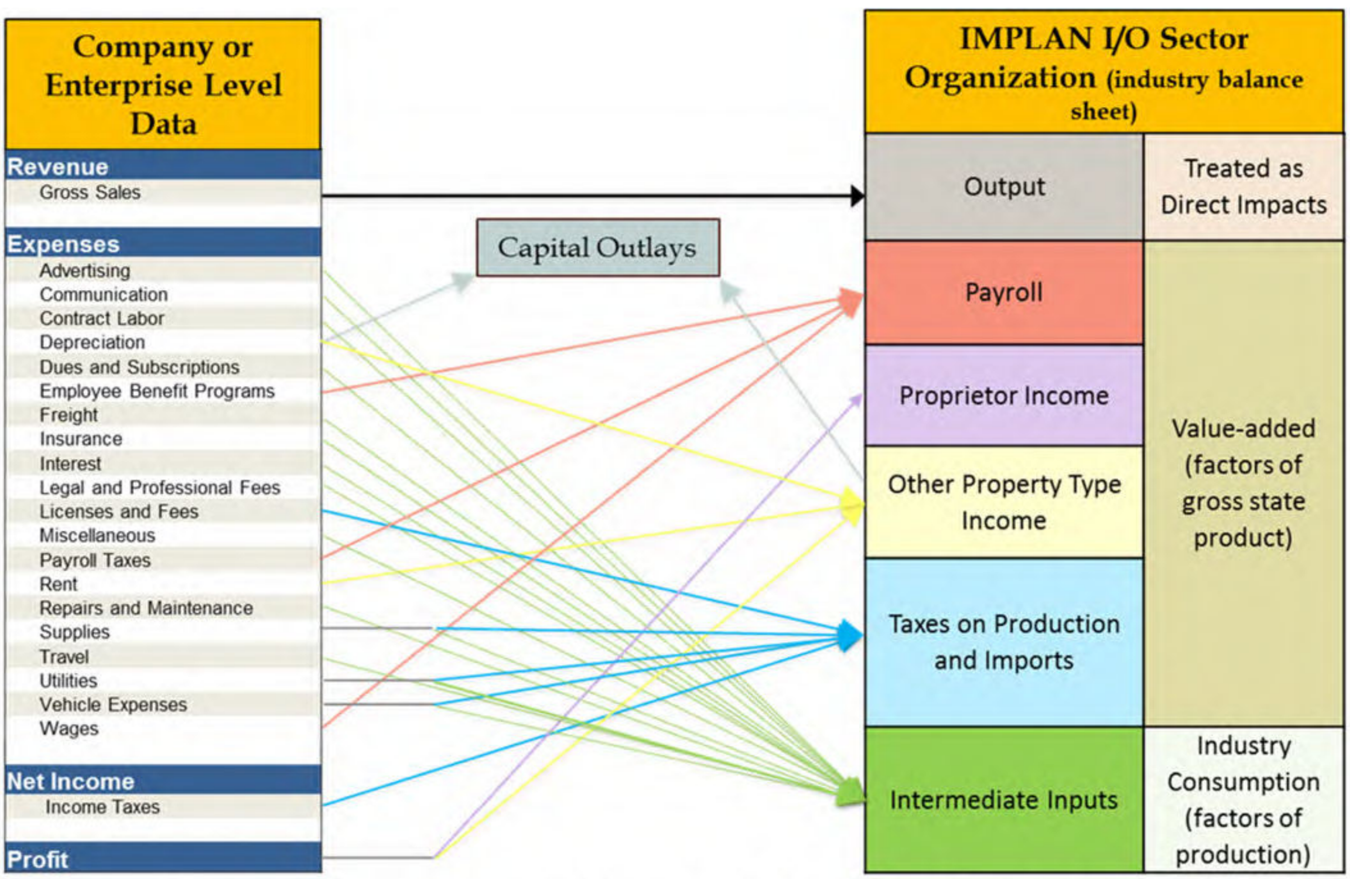
Employment is broadly measured in two distinct categories: covered and uncovered. Covered workers are those that are employed by a business, institution, or government agency, receive a wage or salary, and are subject to unemployment insurance (UI). Jobs that fall under an UI program are called 'covered' employment. Quarterly Census of Employment and Wages (QCEW) employment reported by Job Service North Dakota is 'covered' employment. QCEW data are collected for each state and reported by the U.S. Bureau of Labor Statistics (BLS). Therefore, employment statistics for self-employed individual cannot be derived from QCEW data.



Developing Economic Sector Profiles

An industry balance sheet or economic profile is one of the most important elements in economic contribution studies. Nearly all key economic metrics have their origin within an industry's economic profile/sector. Information and data to create economic sector profiles were collected from surveys of industry firms and data from government agencies.

While the IMPLAN modeling platform provides baseline economic profiles generated from proprietary estimation techniques applied to government data, this study relied on state-sourced data and industry input to create a customized IO matrix. The process of developing study-specific economic profiles and then modifying an IO matrix is time consuming and requires considerable empirical analysis, but the results from those efforts produce a credible and transparent evaluation of an industry's role in an economy.



General Transposition of Financial Information into IMPLAN Economic Sector Profiles

Source: DA Bangsund, Department of Agribusiness and Applied Economics, NDSU

Treatment of Traditional Economic Sectors Supporting Lignite Energy Industry

This summary omits specific details of how the secondary economic effects are distributed among the state's numerous economic sectors and sub-sectors. Several economic sectors support the lignite energy industry by providing inputs and services to various segments of the industry. Examples include manufacturing, financial institutions, legal representation, business services, industrial equipment and machinery, among others. Under some definitions, those activities and sectors are presented as "direct" segments of the industry. However, from the perspective of how this study's input-output analysis was structured, those sectors represent "indirect" economic output of the industry, meaning those sectors are supported and sustained from purchases relating to lignite energy industry mining, conversion, and transportation/distribution.

Acknowledgments

Special thanks are extended to Jason Bohrer, President, Lignite Energy Council, for his leadership, guidance, and information throughout the study, and to Kay LaCoe, Vice President of Communications, Lignite Energy Council who assisted with the surveys and soliciting industry cooperation for the study.

The study authors and study sponsors would like to thank all the companies and individuals that took the time to complete and return the survey materials. This study, with its reliance on industry data, would not have been possible without industry cooperation.

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The authors assume responsibility for any errors of omission, logic, or otherwise. Any opinions, findings, and conclusions expressed in this publication are those of the authors and do not necessarily reflect the view of the NDSU Department of Agribusiness and Applied Economics or the NDSU Center for Social Research.